United States Circuit Court of Appeals

TENTH CIRCUIT.

No. 2550.

COLORADO INTERSTATE GAS COMPANY,
a corporation, PETITIONER,

vs.

FEDERAL POWER COMMISSION; CITY AND COUNTY OF DENVER, COLORADO; PUBLIC SERVICE COMMISSION OF WYOMING; COLORADO-WYOMING GAS COMPANY; and CANADIAN RIVER GAS COMPANY, RESPONDENTS.

No. 2551.

CANADIAN RIVER GAS COMPANY, a corporation,
PETITIONER,

vs.

FEDERAL POWER COMMISSION; CITY AND COUNTY OF DENVER, COLORADO; PUBLIC SERVICE COMMISSION OF WYOMING; COLORADO-WYOMING GAS COMPANY; PUBLIC SERVICE COMPANY OF COLORADO; and COLORADO INTERSTATE GAS COMPANY, RESPONDENTS.

ON PETITION TO REVIEW AND SET ASIDE ORDERS OF THE FEDERAL POWER COMMISSION.

FILED SEPTEMBER 9, 1942.

VOLUME 8—Pages 4351-5063

Peterson then explained the graph (Vol. 68, pp. 9960-9963) as follows:

Peterson referred to the column which represents the year 1939, which column does not quite reach the 1600 line shown on the left of the graph. He stated that this column represented 1,600,000,000 cubic feet per day. The column representing the year 1926 shows a total production of something less than 700 million cubic feet per day.

The blue cross-hatched columns at the bottom of the graph represent the gas that goes into the gas pipe lines and during the year 1926 there was probably not more than 25 million cubic feet per day that was marketed through gas pipe lines out of a total of production of 700 million cubic feet per day produced that year.

As you go through the graph, reading to the right, it becomes more or less self-explanatory. The blue at the bottom of the graph represents the daily average of gas used by pipe lines. The next section going upwards represents gas used in carbon black plants, said columns being cross-hatched. The next section going upwards, which is represented by diagonal parallel lines, represents gas that was processed by gasoline plants, the residue of which was not used in carbon black plants. The remaining portions of the graph represent casinghead gas that was not treated in gasoline plants but was blown into the air, and also represents gas that was blown into the air and/or used during the drilling of wells.

Peterson's withdrawal figures check with the Railroad Commission's estimate. The Railroad Commission has estimated that in excess of 6 trillion cubic feet of gas have been produced in the field up to July 1936. This figure when converted from a 14.65 pound to a 16.4 pound pressure base checks with Peterson's withdrawal figures for the same period. (Vol. XC, pp. 13834-13837.)

Note: It will be observed that these volumes are all given on a 16.4 pound pressure base. The Commission representatives in quoting various figures on gas volumes have uniformly used a pressure base of 14.65 pounds. If desired the 16.4 pound pressure base may be converted to a 14.65 pound pressure base by multiplying the 16.4 pound volumes by 1.11945. (Vol. LXIX, p. 10062.)

Peterson testified on cross examination that the figures used by him in showing gas withdrawals have been checked from every possible angle and confirmed by interviewing operators in the field. (Vol. LXXIII, p. 10634.) He also checked his estimates, where reports of metered gas were not available, with various employees of the Railroad Commission from time to time, which persons are familiar with the field through daily contact with it and have confirmed the reasonableness of his estimates (Vol. LXXIII, pp. 10632, 10625, 10627); that such figures have been used in litigation with the Railroad Commission and never questioned by it. (Vol. LXXIII, p. 10597.)

The witness also checked Cotner's figures for withdrawals prior to 1932 and found them to be approximately correct. (Vol. LXXI, pp. 10335, 10336.) Cotner's estimate of withdrawals are regarded by everyone in Texas Panhandle Field to be as good as can be made. (Vol. LXXI, pp. 10340-10345.)

Cotner had access to the records of gasoline plants which were not available to the public, which plants at that time were highly competitive and kept abreast of not only what they produced themselves, but what their competitors were utilizing. Cotner also collaborated with practically all of the geologists that were then working in the Texas Panhandle Field. (Vol. LXXI, pp. 10341, 10342, 10346, 10347.)

In estimating gas blown into the air during the drilling of wells, the witness stated that he had reports on the wells drilled, both gas wells and oil wells, and the open flows of gas wells, and with this information and with information as to the total hours utilized in drilling through pay formations he made estimates as to the amount of gas that was blown into the air and used while the wells were being drilled through the gas producing formations. He has kept a very careful record of this on wells drilled by Texoma Natural Gas Company, this being a part of his duties as Chief Geologist of that company. He kept a chronological record showing the gauges of the volumes of gas encountered at fifteen-foot intervals and the number of hours engaged in drilling and by adding up these amounts after a well was completed he could determine the total volume of

gas that was wasted into the air, as compared to the open flow volume of the various wells drilled and by this means he worked out a factor based upon the open flow volumes encountered. The methods of drilling utilized by Texoma are the same methods utilized by other operators in the field and it takes about the same time to complete a well through the producing formations. His factor is somewhat different for each county in the field, based upon the time required to drill through producing formations in various portions of the field. The average volume of gas lost for each well drilled during each year has remained about the same for each year. Pay formations can be drilled in a shorter length of time in some counties than in others and this accounts for his different factor for each county. (Vol. LXXIII, pp. 10636, 10641-10646. Vol. LXXIV, pp. 10753, 10754.)

The witness has also worked out a formula for estimating gas lost in drilling oil wells. This was determined by studying the drilling records of a great many oil wells and the volumes of gas ordinarily encountered in oil wells at different depths and by determining the number of days the gas encountered would blow into the air before an oil well was finally completed, and this averaged about 5,000,000 cubic feet for each oil well drilled as the volume that would be wasted into the air during the drilling of each well. (Vol. LXXIV, pp. 10057-10059.)

Peterson also prepared and introduced Exhibit 206-A, which Exhibit was admitted in evidence, and which is supplemental to Exhibit 206. Exhibit 206-A merely shows the gas withdrawal figures in the Texas Panhandle Field for the year 1940, and the cumulative withdrawal figures to January 1, 1941, which Exhibit is shown in Vol. 69, pp. 10037-10039, inclusive, and which is as follows:

EXHIBIT NO. 206-A.

Gas Withdrawals From Texas Panhandle Field During 1940.

In estimating the total gas withdrawals for 1940 the methods described as used in estimating total gas withdrawals for the year 1939 were employed. The total gas pro-

duced from the Texas Panhandle Gas Field during 1940 was estimated as follows, on a 16.4 pound pressure base:

	Total MCF	Daily Average MCF
Gas used by gas pipe lines	235,860,805	644,428
Gas used by gasoline plants	337,256,848	921,467
Casinghead gas not treated blown in air	7,320,000	20,000
Gas blown in air and used drilling wells, etc.	17,029,476	46,529
Total gas produced	597,467,129	1,632,424

Residue Gas Used For Carbon Black.

Carbon black is made by burning residue gas from gasoline plants. Thus, gas used for carbon black is included in the above totals showing gas used by gasoline plants. Following is the amount of gas used for carbon black during 1940, on a 16.4 pound pressure base:

Total gas used MCF	Daily Average MCF
262,487,147	717,178

It will be noted that during 1940, as compared to 1939, there was an increase in the total gas produced of 25,187,712 MCF. Increases were as follows:

	MCF
Gas used by gas pipe lines	13,560,900
Gas used by gasoline plants	7,603,575
Casinghead gas not treated	20,000
Gas blown in air and used drilling wells, etc.	4,003,237
	25,187,712

Total Withdrawals to January 1, 1941—
16.4 pounds pressure base

Referring to Table I, the total withdrawals to

January 1, 1940, were	7,728,518,237	MCF
Adding withdrawals during 1940	597,467,129	"
Total withdrawals to January 1, 1941, are	8,325,985,366	"

Peterson further testified on cross examination (Vols. 72 and 73, pp. 10422-10570) as follows:

Q. Why didn't you look at a core from an oil well if you wanted to get the relative condition?

A. I have obtained all of the porosity core determinations that I could obtain of different wells—different oil wells, and I didn't have any correspondence to look at, to tell the truth. I have seen a number of cores of oil wells.

Q. These reports on cores that you got from other companies, they weren't of any particular use to you, were they?

A. They were of great use to me.

Q. In what respect?

A. Well, they tend to absolutely corroborate my idea of what the average porosity is in the Panhandle field.

Q. You don't even know what formation those cores were taken from.

Mr. Spencer: He has testified as to the formation.

Mr. March: As to whether it is the best pay or the poorest pay of the oil well, or what-not.

The Witness: Are you making a statement?

Mr. March: I am asking you if that isn't correct.

The Witness: Can you read that statement he made? I wasn't paying much attention to his statement and I don't remember it.

(The question referred to was read by the reporter as set forth above.)

The Witness: I don't think the companies were lying when they gave me the description of those cores and they stated in each case that those cores were taken from the dolomite formation, and as I said, we don't dispute the fact that you may not be able to obtain a core in the richest part of the formation, although I have gotten some cores here from the Shell Petroleum Corporation which were taken all the way through the pay.

By Mr. March:

Q. Let's look at this Phillips matter marked for iden-

tification and see whether it was taken from the best wells where you could compare a record of porosity determined from samples of cuttings, do you?

A. Well, I know it is kind of a strange thing, but I have—although I am submitting certain exhibits showing porosities obtained in the dolomite oil area, there are many more determinations that I have seen that I cannot offer in evidence because they are confidential and the peculiar thing about it is that you always come out at about the same average on these core determinations that you find. That is the reason I was trying to bring out regarding these papers which I have identified as exhibits the average porosity shown.

Q. But those porosities were determined from cores. I asked if you had any porosities of oil wells which were determined from cuttings.

A. I haven't claimed that any determinations have been made from cuttings.

Q. You don't know of anyone that has made any oil porosity tests in the Panhandle field from cuttings, do you?

A. As a matter of fact, I do, but I haven't had access to them.

Q. You haven't had access to them?

A. No, sir.

Q. You don't know what they are?

A. No, sir.

Q. I want to go to the top of this well where you are getting out these cuttings from the pay formation and where the particles are blowing out. You said you put some sort of an instrument or pipe on there where you could separate the gas from the particles so the man could get in there and catch those particles?

A. No. We put in a vent line. This vent line extends for about 150 feet from the derrick floor. It runs out horizontally and then has an elbow, you call it an "L", and a riser is put in. A lot of times we have put on a connection and extension out from the point where the riser goes up into the air. This riser is vertical, that is, as with respect to this horizontal vent line.

As the gas blows the cuttings out of the hole the cuttings come through this vent line at a very fast rate and will

go into this section of pipe. It just blows them horizontally into it before the gas goes out through the vertical riser and in that way you can get cuttings.

Q. About like the diagram here?

A. Yes, sir. That would give you a good idea.

Q. The pipe goes into crooks and then goes into dead end and the residue blows into the air?

A. Yes, and the gas will hit this—

Q. It will hit the first turn in the pipe?

A. This end here (indicating).

Q. It will hit the dead end?

A. Yes, sir, it goes out there.

Q. The larger cuttings will do that but the smaller cuttings from the best pay formation will blow into the air?

A. I haven't claimed I could get the cuttings from the best pay formation.

* * * * *

Q. Mr. Peterson, have you used your cuttings in any manner in arriving at your permeability?

A. No, sir.

Q. Nor as to open flows?

A. Not the cuttings, no, sir.

Q. Nor as to gas in place?

A. I have formed a judgment on a study of the cuttings which helps me to determine what the gas in place might be; which helps me.

Q. From your cuttings?

A. Yes, sir.

Q. If you can determine permeability from your cuttings, how can you do that when you can't rely upon the accuracy of those permeabilities from cores?

A. I haven't said that and I don't claim that I have ever determined the permeability of my cuttings.

Q. Have you determined the permeability of any wells?

A. I don't know. I wouldn't know what the permeability of a well was. Of course, it would depend upon the size of the casing and how much the diameter was. A casing with a large diameter would have a very great permeability.

Q. You have never determined the permeability of any gas wells in the Panhandle field?

A. No, sir.

* * * * *

By Mr. March:

Q. Is this all of your working papers on pay thickness?

A. This gives the result of all of my working papers on pay thickness. I would have to use the logs of the well and a lot of information that I gathered at different times and these pay thicknesses have been determined by work that was started way back in 1931. They were determined not for any hearing but for the purposes of getting information for the company. I had to use different logs, of course, in the preparation of this exhibit. The names of the wells are given there. I want to say the wells listed there are from logs in my collection at Amarillo and they have all been copied by members of the staff of the Federal Power Commission. Undoubtedly they are in their possession.

Q. I haven't asked you for those logs as yet, but the logs and this constitute the only working papers on pay thickness?

A. Yes, sir, that together with having working papers, because I have had to find out about lots of these well pay thicknesses by consulting with drillers, tool pushers—

Q. Tool dressers?

A. No, I don't think I have consulted any tool dressers, but tool pushers are quite different from the tool dressers. A tool pusher is a person who has charge of drillers ordinarily for a contractor and sees that the work is done and keeps the men supplied with the material necessary, and generally is pretty well informed on what is going on at a well, and watches things and sees that they are done in an efficient manner.

Q. I notice you have 627 wells here. Are those the 627 wells you used to get your 70 per cent pay thickness?

Mr. Keffer: Seventy what?

Mr. March: 70-foot pay thickness.

The Witness: Yes, sir.

By Mr. March:

Q. You didn't use any but these 627 wells?

A. No, sir.

Q. Will you just describe for the record the contents, how you got this data set up by wells?

A. This is a list of wells showing—wells that were used in determining my pay thickness. The sheet as set up shows the well description—for instance, the name of the company is given and then the farm name and number of the well; then the location of the well, that is, the portion of the section that it is in, and then the section number; the block number and the survey number, which identifies the well on the map. Then the pay thickness is given, which was determined for the well.

Q. How did you determine the 627 wells you used? Do you think that is covered in your written statement sufficiently?

A. Well, this is a pretty good description given here.

Q. If you are satisfied, I will withdraw the question.

The Trial Examiner: Are you withdrawing the question?

Mr. March: That is right.

Q. I believe you stated you divided the wells into sections?

A. Into sectors.

Q. You divided the sour gas from the sweet gas?

A. Yes, sir.

Q. You mostly followed county lines, did you not?

A. Yes, sir. The divisions have been made simply to give a convenient area to use.

Q. That is the only purpose of the divisions, is that right?

A. Well, to try to get a representative area so that each well—in each case the spacing of most of these sectors is practically the same in each sector. I would say that the spacing of the wells is more or less uniform in each of the sectors, taken separately, but if the sectors were grouped, you wouldn't get a true average. I have tried to get the best average—,

Q. You wouldn't get a true average?

A. I have tried to get the best average I could in each sector.

Q. What if you took the whole field and ignored sectors, would you get a representative average?

A. It would be hard to get the spacing of wells available to give an even spacing of the whole field. I have tried to space these wells evenly so the average of any sector would be representative.

Q. What would be the difference if you didn't take the sectors individually in your figures as to pay thickness?

A. It would be hard to get a good average. That is all. That is because it would be hard to get your—in some of those divisions I think I used more wells than in others and that is the reason they are divided into sectors. I could use closer spacing in one sector and set it out—if another sector had a wider spacing I would use that sector and divide it up that way. That was the reason, just to try to get a more accurate average of the areas represented.

Q. You made a calculation to ascertain what sort of an average you would get if you hadn't had the sectors?

A. There wasn't—the sectors were made—if we would have had to take an average of the field, that is, if I hadn't divided it into sectors—well, let's take up the Potter County area. There your wells are very widely spread. If you had taken an average of the field and included Potter County wells with an area like Wheeler County, where you have wells on every 160-acre tract, or wells in Moore County where you have maybe a well in every section, the average wouldn't be near as true as the one you have gotten here.

Q. In other words, you divided the field up into quadrants and you are getting at your average for each quadrant?

A. I didn't intend—

Q. What would be the difference in calling these areas quadrants and sectors?

A. A quadrant is one-fourth of something.

Q. Do you recall Mr. Hammer's exhibit where we designated the sectors as quadrants?

A. I don't know how he did it. He had sixteen quarter parts in the Panhandle field.

Q. That is the only reason you wouldn't want to call them quadrants? If I referred to them as quadrants you wouldn't like that, would you?

A. No, sir. A quadrant means a quarter part of something.

Q. Do you know the United States Geological Survey has quadrants designated as they are not quarter parts?

A. No, sir. As I remember it, the U. S. G. S. publication divided it into quadrangles.

Q. Quadrangles?

A. Yes, sir.

Q. Is that right?

A. Yes.

Mr. March: It is about noon, Mr. Examiner. I can continue on but we might recess now.

The Trial Examiner: We will recess until 2:00 o'clock this afternoon.

(Whereupon, at 12:30 o'clock p. m., a recess was taken until 2:00 o'clock, p. m., of the same day.)

Afternoon Session, 2:00 P. M.

The Trial Examiner: The hearing will be in order. Whereupon—

C. J. Peterson the witness on the stand at the time of recess, having been previously duly sworn, resumed the stand and testified further as follows:

Cross Examination (Continued).

By Mr. March:

Q. These 627 wells, they are just how extensively scattered over the field?

A. Just about what?

Q. How extensively scattered over the field?

A. Well, let's take a look at that.

Q. Do you need your working papers on that?

Mr. Spencer: No, it is in his written statement.

The Witness: Exhibit 206.

By Mr. March:

Q. While we are looking at this thing, I want to tie in this 627 wells to this Table 2 on Page 9 of your Exhibit 206. That is the 627 wells referred to there, is it not?

A. Yes, sir.

Q. Which are contained in this working paper?

A. You asked how they are distributed over the field?

Q. Yes.

A. Well, in the Carson County sweet gas area, 103 wells.

Q. You don't need to read all of that. I notice here that you indicate the numbers of wells which are found in various counties and sections, but I wondered how they are distributed over the various counties.

A. Well, the location is given in that working paper.

Q. By looking at this working paper I can determine the location of these various wells?

A. Yes, sir. That was an exhibit made up so that those wells could be located on a map.

Q. I notice here you only have 16 wells in Potter County.

A. Yes, sir.

Q. 16 wells in Potter County.

A. Yes, sir.

Q. Is it not true that most of Canadian River's acreage is in Potter County?

A. Well, I wouldn't say most of it is. I have never analyzed it. I believe most of it is, though.

Q. How many Canadian River wells do you have here?

A. Well, I would have to look at the list there to tell.

Q. Just an approximate figure is all I am interested in.

A. Canadian River and the Amarillo Oil Company which—and the Red River Oil Company which are—

Mr. Spencer: Owned by the same parent company.

The Witness: Have the same parent company—there are 16 wells. That would be the total of Canadian River wells.

By Mr. March:

Q. You don't have anything but Canadian River wells in Potter County, do you?

A. No, sir.

Q. What is the average thickness of Canadian River acreage in Potter County of those wells, approximately?

A. The average thickness is at 92.19 feet.

Q. How many for—the only other Canadian River wells I believe are in Moore County, are they not?—and Hutchinson County, or do you have any in those two counties?

A. Hutchinson and Moore—you mean in Hutchinson

County—at least four Canadian River wells in Hutchinson County.

Q. At what average pay thickness?

Mr. Spencer: Do you mean for the county or for the four Canadian River wells?

Mr. March: For the four Canadian River wells.

Q. You might read off which four they are there.

A. The four wells that I have used in Hutchinson County, sweet gas area, are the Amarillo-Bivins No. B2, 1320 feet from the east line, 820 feet from the south line, Section 90, Block 46, H & T C, 65 feet.

The Canadian River Dunaway, B1, 362 feet from the north, 1645 feet from the east, Section 5, *Blocy* Y-2, 100 feet.

The Canadian River Dunaway 2A, 2300 feet from the east line, 2310 feet from the south line, Section 5, Block Y-2, 58 feet.

The Canadian River Bivins B1, Section 11, southwest corner of the northeast quarter of Section 11, Block Y-2, 138 feet.

This makes a total thickness in all of 361 feet and an average thickness of 90 feet.

Q. Now, that is only a small area there. Let's see which wells you have left out of there. There are four wells in there which Canadian River has, aren't there? Which Canadian River wells did you leave out from your pay thickness calculations?

A. Well,—

Q. You can look right here on this map, Exhibit 95, and tell.

A. Yes. There are four wells there.

Q. Yes.

A. I will try to locate these wells.

Mr. Spencer: Won't the map itself, Mr. March, show sufficiently what wells he did not use?

Mr March; Well, if I get this working paper in evidence I think it will.

Mr. Keffer: He has already put the wells in evidence.

Mr. March: The wells aren't in evidence.

Mr. Keffer: Well, the map is in and the list is on the map.

Mr. March: The working paper is not in evidence yet. I want to check on this little corner. I want to know what wells he left out.

Mr. Keffer: And the map shows it. That's what I am stating.

Mr. Spencer: We are willing to stipulate that he did not use them all.

Mr. March: Oh, I know that. I know he didn't use them all. That is a very small corner there and I am just going to ask him about that.

Q. Can you read the open flow of those wells?
A. Here is a well in Section 11, Block Y-2, shown here, 76 million cubic feet, I believe—76 million cubic feet.

The next one is in Section 90, Block 46, 40 million cubic feet.

The next two are in Section 5, Block Y-2; one of them has 34.8 million cubic feet and the other one has 30.8 million cubic feet.

Q. Now, will you take those wells that you did not use and read off the open flow of those wells—Canadian River acreage?
A. Canadian River acreage?
Q. Yes.
A. Those aren't made up with reference to Canadian River acreage.
Q. I understand that, but it is included.
A. There is a well here in Section 4, Block Y-2, that has 8 million cubic feet.

There is a well in Section 88, Block Y-2,—Block 46, rather—that has 70 million cubic feet, and a well in Section 13, Block Y-2, that has 58 million cubic feet, just north of the one that we used that had 76 million cubic feet.

There is a well in Section 9, Block Y-2, that has 45 million cubic feet.

Mr. Spencer: Are those initial volumes you are reading, Mr. Peterson?

The Witness: These are initial open flows, yes, sir.

There is a well in Section 13, Block Y-2, that had 75 million cubic feet.

There is a well in Section 10, Block Y-2, that has 7 million cubic feet.

By Mr March:

Q. Is that all that you did not use that are in the Canadian River acreage in Hutchinson County?
A. I believe so.
Q. Do you know what the pay thickness of those wells is that you didn't use?
A. No, sir, I couldn't determine it.
Q. You could not determine it?
A. No, sir.
Q. You didn't have records you could determine it from?
A. Those wells were drilled a long while ago and it was very hard to determine the exact pay in them.
Q. Were all those you did use drilled subsequent to the wells you did not use—these you read off last?
A. I wouldn't swear on that, but it must be understood in trying to make an estimate of this kind one has to use the most reliable data he can get hold of. Otherwise, the work wouldn't be very reliable.
Q. Have you got logs on those wells you didn't use in Canadian River acreage in Hutchinson County?
A. Yes, sir.
Q. Could you have taken those logs and determined it on the wells that you did not use?
A. I believe you would find out that they are pretty hard to use, if you tried to compare them.
Q. Well, the only reason you didn't use these other wells is because you didn't have accurate data in regard to them?

Mr. Spencer: He hasn't said that was the only reason.

By Mr. March:

Q. Is that the only reason?
A. That is one of the reasons. It is not the only reason.
Q. You wouldn't want to state for the record here that

you didn't have as good data on them as you had on the others?

Mr. Spencer: He has already stated that.

The Witness: I have already stated that. That is one of the reasons. There are two reasons why I picked my wells. One is to get accurate data and the other one is to try to get more or less even spacing in the wells that I can get hold of.

By Mr. March:

Q. You find out for me which of those wells you used were drilled subsequent to those you did not use.

Mr. Spencer: Now, Mr. Examiner, unless the Examiner thinks that is important, we are not going to encumber Mr. Peterson with a lot of miscellaneous, various and sundry requests by Mr. March to furnish information on things which we think are not material.

Mr. March: If you don't want to give us those, I can get those from Mr. Thompson's working papers, I think.

Mr. Spencer: You can get it from your own working papers.

Mr. March: I don't think so.

The Witness: Don't you have the wells?

Mr. March: We may have in Washington. I have wired for 627 logs and I expect to look at every one of them.

Q. Now, let's move along over here to Moore County. How many Canadian River wells do you have in Moore County, approximately?

The Trial Examiner: Mr. March, do you mean how many wells did he use in Moore County?

Mr. March: Yes, how many wells did he use in Moore County?

Mr. Lange: In this Table No. 2.

Mr. March: Yes.

The Witness: Do you want to include the Red River?

Mr. March: Is the Red River a subsidiary of the Canadian River or wholly-owned—that's right, it is an affiliate—

Mr. Spencer: He understands—

Mr. March: He just asked me the question.

Mr. Spencer, I would like to ask you for the record: Those Red River wells, are they tied into local Texas service and not into the Denver service?

Mr. Spencer: That's right, using the term "local" relatively. They aren't tied into the Canadian River system.

The Witness: 16 wells altogether.

The Trial Examiner: Are those the Canadian River wells?

By Mr. March:

Q. Are they Canadian River wells?

The Trial Examiner: That was the question.

By Mr. March:

Q. In Moore County.

A. They are all Canadian River except one or two Red River wells.

Q. Let me see one or two of those Red River wells there. Let's see what the thickness is.

A. Red River, Shelton 1-A—is that supposed to be Red River?

Mr. Spencer: That's right.

The Witness: That's one Red River well. Canadian River Thompson well—Canadian River Reed 2-A.

The Trial Examiner: Did you get that, Mr. Reporter?

By Mr. March:

Q. Now, do you know how many Canadian River has up there in Moore County altogether—what percentage of the wells in Moore County that Canadian River has that you took?

A. No, sir, I don't.

Q. Do you know whether or not those wells that you

took have the highest pay thickness according to your own calculation?

A. The ones I took are the only ones that I have been able to determine the pay thickness on, so I couldn't very well answer the question.

Q. How many wells has Canadian River got altogether and Red River combined, since you have got both of them combined here in this discussion?

A. I don't know.

Q. You don't have any idea?

A. I have never counted them.

Mr. Spencer: Well, why mix Red River into it?

Mr. March: Well, we have got—

Mr. Spencer: There is just one in there.

Mr. March: Well, there are several more over in Potter County. Leave Red River in there. I will ask you this question:

Q. How many producing wells does Canadian River have?

A. I don't know.

Q. You never made an examination of those wells to ascertain how many they have got?

A. I never counted them, no.

Q. You didn't look over every well Canadian River has in order to arrive at which ones you would use?

A. Oh, yes, but I didn't count them at the time.

Q. As I say, you have only got 32 Canadian River wells and Red River wells in there in Potter and Hutchinson County—36—16 in Potter County, 4 in Hutchinson, and 16 in Moore?

Mr. Spencer: If you are going to make anything out of it, let's let the witness go back and count and see what he has got.

The Witness: I tried to pick out the wells that I could use and I didn't pay any attention to what company they belonged to.

The Trial Examiner: I believe that is his testimony, Mr. Spencer.

Mr. Spencer: In one instance, Mr. Examiner, he combined Red River with Canadian River wells. They weren't separated.

The Trial Examiner: That's right, in Moore County.

Mr. Spencer: I am willing to stipulate any figures you want.

Mr. March: Does 92 wells sound right for Canadian River?

Mr. Spencer: More than that.

Mr. March: About how many?

Mr. Keffer: I think today it is a hundred, isn't it—98—it's a hundred wells for Canadian River and I think now there are just—wait just a second. I can tell you how many Red River has. (Examining Exhibit 95). I think there are 13 wells of Red River and 1 now drilling that started since we came up here, since the first of the year, and I don't know whether it has been completed yet or not. It might be 14.

Mr. March: That would make 112 altogether?

Mr. Spencer: That would be a close approximation, yes.

By Mr. March:

Q. With 112 wells you could only get 36 wells on which you could make any determinations at all as to pay thickness, is that right?

A. No, I wouldn't say that.

Q. What would you say?

A. Well, when I made up this exhibit I took what was available that I could determine the pay thickness on. I think they have drilled several since I worked on this exhibit that I could obtain the thickness of, but in this area, Moore County, except the southwest corner. I have used 87 wells in all which are pretty well scattered over that whole area—pretty well spaced, and in Potter County I used all of the Canadian River wells there, which are pretty well spaced, too, for that part of the field, and in Hutchinson County itself, in the sweet field—the west sweet field, which is in that corner, I used 24 wells altogether. Of those

wells, 4 of Canadian River wells. That is a pretty good representation when you consider the acreage. It makes a pretty good spacing.

* * * * *

Q. Thickness is a pure laboratory calculation, is that right?

A. I wouldn't say so.

Q. It is more of a judgment figure?

A. No, it takes in a lot of careful work to get your thickness figured up—investigations.

Q. How would that have affected your estimate of pay thickness if you just used 16 wells in West Gray County? Do you think that would have raised your figures any as to pay thickness?

A. The reason that I have divided these sectors up is that in that way you can get a better average of each area that will be representative than if you took, say, Potter County 16 wells and then went up to Moore County and took 16 wells, or 32 wells. You would have to do that all over the field if you tried to take the field as a whole. You would have to take just about the same number of wells all over the field regardless of your information and it wouldn't give you as good a picture as I have gotten. The whole object—if you will notice, each of these sectors is a separate sector, and the sectors are not balanced with each other. They aren't related to each other at all for getting your results. No sector has been added in with another or balanced with it, or whatever you want to call it. I just made the best determination I could in each area. The reason I got more wells in one area than in another, if I could get the spacing that would justify taking that number of wells, why, I took them.

Q. I note here, and it is very interesting to me, that there are 65,445 acres in the west Gray County wet—sweet gas area, and in Potter County there is 107,347 acres.

A. Yes, sir.

Q. In the sweet gas area—and in Potter County you take 16 wells in spite of the greatly exceeding acreage, and in west Gray you take 77 wells. How do you account for any such action as that?

Mr. Spencer: Mr. March, if you had been listening instead of being so interested, he just explained it was a matter of spacing. He took the greatest number of wells

he could find where he could get them properly spaced. He has just gone through it right ahead of your question.

By Mr. March:

Q. Is that your answer?

A. Why, certainly. That is the reason I made these different sectors because I couldn't get—I'd like to have gotten a hundred wells in every one of those places if I could, because it was an important—there were only 16 wells in Potter County. I couldn't build a lot more wells.

Q. Did you say there were only 16 wells in Potter County?

A. Only 16 that I have been able to use.

Q. There are considerably more than that in Potter County, though, aren't there?

A. Yes, there are more than that.

* * * * *

By Mr. March:

Q. Now we come to the actual determination of pay thickness or the actual procedure by which that pay thickness is determined. As I read your statement and as I have listened to your testimony here, although you have logs on these 627 wells, that you do not rely upon those logs solely for your determination of pay thickness.

A. No, sir.

Q. Why don't you rely on those logs for the determination of pay thickness?

A. Because some of them were rather inadequate and I was able to check, though, and get some information at different times that gave me a clue to use them.

Q. Where are the notes and the data which supplement those logs?

A. I haven't any data to supplement them because I made—as I say, if I had been preparing this for an exhibit, I would have a lot of data, but I wasn't preparing it for an exhibit. At least I didn't have any idea of ever offering it as an exhibit when I worked it up.

* * * * *

Q. Has your estimate of reserves over the years changed much?

A. No, sir. As I got more information, I have tried to improve it. I want to draw the—I would like to draw your

attention, Mr. Examiner, to something about this estimate—just an explanation.

The Trial Examiner: Well, it is a matter of explanation of an answer to a question that Mr. March has asked—

Mr. March: I have no objection, Mr. Examiner.

Mr. Spencer: Is what you are going to say in explanation of some answer you have made to a question propounded by Mr. March?

The Witness: I wanted to draw attention to the method used in obtaining the thicknesses—that is, the method by which the area is divided all the way through—this whole area.

Now, for instance, referring to the Table 2 in Exhibit 206, you will note I summed up the total thickness, for instance, in Carson County—103 wells—summed up the total thickness and then divided by the number of wells used and that gave me an average per well of 85.82. Now, since I used 103 wells there, in order for there to be a difference, we'll say, of one foot in my average, I would—that would accommodate an error of 103 feet—if I had a total error of 103 feet, why, that would only make a difference of one foot in my average, and if you consider the whole 627 wells that have been used, to accommodate an error of one foot in my average, would necessitate an error in the whole computation of only—of over 627 feet so that if I did make errors, why, the whole process lends itself to dividing the area. This is further carried on when the averages—when it is averaged—the average obtained and weighted per acre.

In Table 3, the average obtained for each area is multiplied by the acreage obtained in the acre feet, and then the whole is divided by the total number of acres in the error which is 1,339,700, which serves further to serve as the method—it lends itself to dividing the area, whatever it might be in greater thickness or less thickness. You would have to have an awful big error there to shorten the average in the end.

* * * * *

By Mr. March:

Q. Who were some of those drillers you were talking to?

A. I am not going to attempt to tell you because it is impossible for a man to remember people ten years back.

Q. Can you tell us one driller you have talked to who has agreed to tell you about the pay thickness?

A. I am not going to tell you about any of it.

Q. You wouldn't tell me any of their names?

A. I have consulted some of them but I'm not going to try to get into that.

Q. I will ask you to cite a single driller who will agree with you as to pay thickness.

The Trial Examiner: What's that?

By Mr. March:

Q. I will ask you to cite a single driller who will agree with you as to pay thickness of a given well.

A. I didn't say that they agreed with me as to pay thickness. I said by investigating and talking to them I determined what the pay thickness was.

Q. If they didn't agree with you, how could you determine it?

A. I could find out what they were drilling through—when they were drilling through the pay thickness and what the pay thickness was. They didn't try to determine pay thickness. They would tell me how they were drilling at different places and where they got the pay, but they didn't add it up or try to determine it.

Q. These logs don't even show pay thickness, do they?

A. A lot of them do. I just said that I used a lot of logs just as they were. I already have made that statement.

Q. If you don't want to tell me the name of a single driller, that is all right. We will now go to this 12½ per cent of the drillers you talked to. I want to know the 12½ per cent of the other type of men you talked to. They were the pushers, you say, and the people keeping records on the well?

A. Yes, sir. I am not going to attempt to estimate any percentages because it is impossible for a man to do it.

Q. I don't want you to. I have all the percentages I need. Now I need a little fill-in here. Can you name a single pusher that agreed with you on pay thickness?

Mr. Spencer: Has he testified the pushers determined sand thickness yet?

The Witness: No, sir. As I say, I have obtained different information from these people that enabled me to determine pay thickness. They never determined pay thickness for me.

By Mr. March:

Q. Who are some of the individuals?
A. I am not going to try to name them. I have seen so many of them, I do not want to try to name them.
Q. Who is one of the pushers?
A. I don't think I am going into that.
Q. That is all right with me. So we get to the 25 per cent now. Did you talk to somebody who had connections with the drilling of the well? Now we come to the other 25 per cent which had no connection with the drilling of the well, but which were officials of the company—
A. They were company representatives—
Q. What were they—geologists and the like?
A. Yes, sir, company geologists and company scouts.
Q. You talked to the Phillips Petroleum Company's geologists on some of their wells as to what pay thickness they had?
A. Yes, I have talked to a number of them at different times.
Q. Did they agree that you could determine pay thickness of any of their wells?

Mr. Spencer: He hasn't testified they determined any sand thickness.

The Witness: I got information from them which I could use.

By Mr. March:

Q. None of the Phillips representatives told you that you contacted in the field, this 25 per cent of the representatives of the companies you contacted in the field, told you and agreed with you as to the pay thickness?
A. Yes, I have asked them at different times as to what the pay thickness would be—what they thought the pay thickness would be, and they told me what I said.
Q. Phillips?
A. Yes.
Q. Did they say they could determine pay thickness accurately?

A. They told me what they considered the pay was.

Q. Who was that?

A. Different ones there—

Q. Who, for example?

A. That is kind of hard to go into, trying to tie a Phillips man down to something.

Q. You are relying upon it, aren't you?

A. Certainly, at the time I relied upon it.

Q. Well, the Examiner has to rely on this and we want to have it backed up, if possible, or not backed up—I doubt whether it can be backed up or not. Whom did you talk to?

A. Well, I talked to Tom Craig of the Phillips Petroleum Company about different wells.

Q. Tom Craig gave you the pay thickness?

A. Yes, sir, he told me what he thought was the pay thickness and where he thought the record was inadequate, and other things. You see, we bought quite a number of wells from the Phillips Petroleum Company.

Q. What is Tom Craig?

A. Tom Craig is a geologist for the Phillips Petroleum Company in Amarillo.

Q. Is he in charge of the Amarillo office? Mr. Knight is district geologist, isn't he?

Mr. Spencer: Just a minute. Let the witness answer the other question.

The Witness: Tom Craig was district geologist ahead of Mr. Knight. Now Mr. Knight is district geologist and I don't know Tom Craig's official capacity. It was when he was district geologist I used to consult with him about these wells.

By Mr. March:

Q. About when was that?

A. Back in 1931 and 1932.

Q. You haven't consulted with anybody from the Phillips Petroleum Company since then?

A. Yes, at different periods.

Q. And with Mr. Knight, present district geologist?

A. Yes, sir.

Q. Did he give you the pay thicknesses?

A. No, sir.

Q. Why wouldn't he give you the pay thicknesses?

A. I don't think I consulted him about pay thicknesses.

Q. Who else did you consult?

A. Those are the only two geologists that I have known with Phillips in the field.

Q. You say Tom Craig showed you where the pay thicknesses were inadequate.

A. He didn't think that the record was good.

Q. You never asked Mr. Knight what he considered to be the pay thickness of the Phillips wells, have you?

A. Well, I have had so many conversations with these gentlemen that it is hard to remember just what definite information they gave me at different times. We are all very well acquainted with each other.

Q. So, therefore, none of the 25 per cent here were taken from the Phillips? They were not consulted as to the effective pay thickness subsequent to 1932?

A. No, sir.

Q. You just said Mr. Knight didn't give you any opinion as to pay thickness?

A. I said I couldn't remember what I talked with him about at different times, but he has helped me on pay thickness; that is, he has given me information.

Q. Are you familiar with his testimony that you can't use pay thickness in the Panhandle field of Texas to determine it?

A. I am not familiar with any of his testimony anywhere. I haven't read any of his testimony and don't know what you mean.

Q. Did he orally inform you that you could not determine the pay thickness of the Panhandle field of Texas?

A. Who?

Q. Mr. Knight.

A. No, sir.

Q. Did he say you could?

A. I have never heard him express an opinion on the subject.

Q. You have never heard him express an opinion on pay thicknesses at all, have you?

A. I have asked him about pay thickness in certain of the Phillips wells—

Q. Which wells?

A. I can't remember now, Mr. March.

Q. What did he say when you asked him about the pay thicknesses of certain Phillips wells?

A. He told me what he thought the pay thickness was in those wells.

Q. I see. I want those wells designated so I can check on that.

Mr. Spencer: He said that he can't remember.

The Witness: I can't possibly remember.

By Mr. ~~March:~~

Q. Did you use a great many Phillips wells in this estimate here?

A. I used a few of them, quite a number of them, but I have never counted them to see what they were.

Q. Were they some that you used here that you talked to him about?

A. I couldn't remember concerning that, Mr. March. This work has gone on over a period of ten years and a man can't remember all of those details.

Q. Did Mr. Knight tell you the pay thickness of the oil wells, or were they gas wells?

A. I have inquired of him about pay thickness in oil wells and gas wells both.

Q. But you can't say whether or not there are any of those used here in your 627 wells that you asked him about?

A. As I say, I can't remember.

Q. I see. All right, we will move along.

What other geologists did you consult, company representatives, did you consult, relative to these pay thicknesses in the 627 wells?

A. Oh, I consulted the geologists of the Texas Company and the geologists—

Q. Just a minute. Whom did you consult with The Texas Company?

A. Mr. Schwartz, District Geologist, at Pampa.

Q. Did they have many gas wells?

A. The Texas Company?

Q. That's right.

A. I think they have quite a number of them.

Q. Were they included in the 627 wells you consulted Mr. Schwartz in regard to?

A. Yes, sir.

Q. Did Mr. Schwartz tell you the way it was done?

A. He gave me no information that helped me to determine it.

Q. Which wells were they? Were they all of The Texas wells here? Can you check through without going through the exhibit here?

A. I can't remember which one I consulted him about. I consulted him with the one idea—

Q. Which one did you consult him about?

A. I can't tell.

Q. No one else can tell by examining those logs of yours?

Mr. Spencer: What someone else can tell, you hardly and I can hardly tell until it is looked at.

Mr. March: I doubt whether you and I could even tell.

Mr. Spencer: You and I are pretty smart. We might be able to take it out of there.

The Witness: Do you expect me to answer a question about what somebody else can or cannot do?

By Mr. March:

Q. You can't tell me, then, the wells you consulted—the wells that you were having trouble with and consulted The Texas Company about?

A. No, sir.

Q. And Mr. Schwartz gave you some information about some wells that you were having difficulty with and he helped you to determine the pay thickness?

A. Yes, sir.

Q. He didn't say what the pay thickness was, did he?

A. I can't remember.

Q. All right, who else did you consult? What other geologists? What other company representatives did you consult?

A. Well, I consulted geologists with Gulf Producing Corporation.

Q. Whom did you consult there?

A. Mr. Terrell.

Q. When did you consult him?
A. At different times during the past ten years.
Q. Is he still district geologist?
A. No, sir, he isn't there at the present time.
Q. How long has he been gone?
A. I don't remember exactly.
Q. Approximately?
A. Less than a year.
Q. Less than a year?
A. Yes.
Q. Mr. Schwartz is still with The Texas Company as a geologist?
A. No, he is not with The Texas Company.
Q. How long has he been gone from there?
A. I can't remember that either.
Q. You don't even remember the last time you consulted him?
A. No, sir.
Q. You haven't consulted him in recent years?
A. No, sir.
Q. You haven't consulted him since 1932?
A. I doubt if I have consulted him since 1932.
Q. When was the last time you consulted Mr. — this Gulf man?
A. I can't remember.
Q. You can't tell.
A. I don't think anybody could remember things like that.
Q. Even approximately?
A. No, sir, not even approximately.
Q. Did you take notes when you consulted people as to the pay thickness, as to the 25 per cent of these walls, these geologists?
A. I took notes when I tried to determine the pay thickness.
Q. Where are the notes?
A. I haven't any of them.
Q. How many did you consult down there?
A. I have consulted the geologists of the Empire, now known as the Cities Service Oil Company.
Q. The Cities Service Oil Company?
A. Yes, sir.

Q. Whom did you consult there?

A. Archie Kantz.

Q. What is he?

A. The District Geologist for the Empire, now known as the Cities Service Company.

Q. Is he still the district geologist?

A. Yes, sir.

Q. About how many of these wells did you consult him about?

A. I can't remember.

Q. You can't remember any particular well you consulted him about?

A. No, sir.

Q. Did you consult him very much?

A. I don't know what you mean by very much.

Q. Did you consult him about a great number of wells or with the few wells you were having trouble?

A. A few wells at various times I wanted information on—I consulted him about those.

Q. Does he have a tabulation of pay thickness of these wells?

A. No, sir.

Q. Do you know of anybody that does have that information but you?

A. I have no way of telling what these men possess.

Q. I thought you went in and talked to them and asked them what the pay thickness was.

A. I asked them for information to enable me to determine it. I am not claiming these men determined my pay thickness.

Q. Did they in any case tell you what the pay thickness was in a number of cases?

A. Yes, sir, in a number of cases.

Q. Did the Cities Service man tell you?

A. Yes, sir.

Q. Which wells?

A. I can't remember now.

Q. If you can't remember which wells, how can you remember whether or not he told you what the pay thickness was?

A. Because I can remember that I had to check some wells up with him and to make my determination.

Q. About when was that?

A. I can't remember which wells there were.

Q. About when was it?

A. I can't remember when it was, except that it was during the past ten years.

Q. It is all very hazy?

A. No. I have never kept a diary on these things.

Q. It is more than I can see how you can keep all of these things in your head to say that a 75-foot pay thickness—

A. At the time I worked this up I took a record of the total pay thickness at the time I determined it. It was on a list and this exhibit—

Mr. Spencer: This working paper?

The Witness: This working paper—

By Mr. March:

Q. Which list was destroyed?

A. No,—

Q. The original list you took it from—

A. I threw it away after I got it typed up.

Q. You didn't throw it away until the Federal Power Commission requested you make up a list like that?

A. I was trying to remember whether I ever had it typed up before—I think I had—after I had it typed up in good form I threw away the old list. What good was it?

Q. My question was, did you have it typed up before the Federal Power Commission made the request for you to produce those pay thicknesses on those 627 wells?

A. Yes, I had it typed up at different times.

Q. Do you have those 627 wells on the list and no more?

A. Yes, that is all I have ever been able to use.

Q. All you have ever been able to use? How many wells are there in the Panhandle field of Texas?

Mr. Spencer: Gas wells?

Mr. March: Yes.

The Witness: Just a minute. I want to qualify that answer I gave. I will say it is all I have been able to use to try to get a representative spacing of the wells.

By Mr. March.

Q. How many more have you been able to use to determine pay thickness?

A. I don't know, Mr. March.

Q. Approximately how many?

A. As a matter of fact, I haven't worked up any more than I have in that list there because that was all I needed for the purpose I was using it.

Q. You picked out those wells and determined the pay thickness on those particular wells?

A. Yes, sir.

Q. In other words, those other wells which you from time to time talked about and maybe made notes in regard to pay thickness on, you don't have any data on those wells at all?

A. The only wells I ever had any notes on are the ones in this working paper.

Q. How many gas wells are there, approximately, in the Texas Panhandle?

A. Approximately 1600.

Q. 1600?

A. Yes.

* * * * *

A. About two and a half miles from the edge of the field.

Q. You said it was how far from the D-4 well?

A. It is about $1\frac{5}{8}$ miles.

Q. All right, did you use that well—Masterson M-1 as I read it here—H-1—it could be N-1?

A. It is the well in that Section 3, Block B-11.

Q. You know which well it is.

A. Yes. I didn't use it, no.

Q. Now, Mr. Peterson, we have made a complete circle around this largest well of the Canadian River Gas Company and we found that you only used one of those wells, the one with 18 million open flow. Now, you can look there. Do you see any wells any closer than the ones I have indicated that we have discussed?

A. The one I used is the one north of the Masterson.

Q. The 18 million open flow well?

A. The 18 million open flow, yes, sir.

Q. Now, Mr. Peterson, why didn't you use any of those

other wells? For example, why didn't you use the Masterson D-4?

A. Well, it probably was on account of the fact that I couldn't interpret the record or get enough information on it. As I say, these thicknesses were determined by using the best information I could get. If I had wells with information that I couldn't use and couldn't satisfy myself that I had a satisfactory determination, I didn't use them.

Q. Is that the reason you didn't use those other wells that I read off?

A. I believe that is the case. These determinations were made up a long while ago and not for any litigation or anything. They were made up in trying to get definite information that I thought was reliable.

Q. In your opinion, did that one pay thickness on that one well, assuming it is correct, does it indicate the pay thickness of that region?

A. Well, averaged with other wells in the big area involved in Potter County there, in wide spacing, why, it gives a pretty good average of that area.

Q. How do you know? You don't know what the pay thicknesses of those wells are.

A. No, sir.

Q. Does the pay thickness vary with your open flow?

A. Not necessarily.

Q. Well, you just don't know what the pay thicknesses of the wells are in that entire region, then, do you? It's bound to be variable, isn't it?

A. Sometimes you can't always get all the information you want in a region, but I am trying to get an average of the area as a whole.

* * * * * * *

By Mr. March:

Q. You haven't made an estimate of reserves of the whole field on the open flow method of estimating reserves, have you?

A. I have never said that I had used an open flow method of estimating reserves.

Q. All right. Do you agree with this statement—reading from Page 895 of the Cotner and Crum report.

"The great variations of open flow of wells in the Texas Panhandle field indicates considerable differences both in porosity and thickness of pay strata."

The Trial Examiner: That is from Exhibit 215?

Mr. March: Yes.

The Witness: What page is that on?

Mr. March: I am reading from Page 895.

Mr. Spencer: How does that quotation begin?

By Mr. March:

Q. "The great variations of open flow of wells in the Texas Panhandle field indicates considerable differences both in porosity and thickness of pay strata."

The question I am asking you is, do you agree with that sentence here?

A. Well, if you put in the next sentence with it.

Q. I am asking you about that sentence, then I'll ask you about the next one.

Mr. Spencer: That is a complete answer. He says yes with the explanation.

Mr. March: Let him put in the explanation. I don't care.

Mr. Spencer: That's all we are talking about.

The Witness: The next sentence says, "porosity is the main factor."

By Mr. March:

Q. Then you do agree and you do contend that open flow has a direct relationship to pay thickness, is that right—contrary to your previous contention?

A. No, sir, that is not what it says here.

Q. Then you don't agree with it—I mean you don't agree with the statement I just made?

A. Let's hear the statement.

Mr. Spencer: I have difficulty whether you want him to agree with you or Crum and Cotner.

The Witness: I thought you were talking about Crum and Cotner.

Mr. Spencer: Wasn't that answered?

Mr. March: No, there wasn't, and I don't want to be deferred. I want it answered.

(The record referred to was read by the reporter as set forth above.)

The Witness: I think I answered that. I stated it two or three times that you can't determine pay thickness by open flow.

Mr. March: All right, that's all there is to it.

Now, do you know for certain where those small particles are coming from when they are blown out of the well, whether they are coming from the pay or what-not?

A. Well, the particles themselves generally speak for themselves.

Q. Do you know?

A. You can tell by an examination of the particles whether it comes from the pay or not.

Q. How can you tell that?

A. You can tell by the appearance of it and by examining it. Is shows the porosity.

Q. It shows the porosity?

A. Yes, sir.

Q. Can you determine the porosity mathematically from the samples?

A. You can get an idea from looking at them.

Q. Can you give me the porosity determination you made on any well?

A. No, sir. I was just trying to get ideas of the situation down there as a whole. I have examined hundreds of thousands—thousands of samples to base my opinion upon that.

Q. Have you a single record down there that shows the result of an examination of any well for porosity, what the porosity of that well was?

A. No, sir.

The Trial Examiner: We will stand in recess for five minutes.

(At this point a short recess was taken, after which proceedings were resumed as follows:)

The Trial Examiner: The hearing will be in order.

Mr. Spencer: May I ask the witness one or two questions, Mr. March?

Mr. March: Yes, sir.

Mr. Spencer: Will you explain to the Examiner the different uses that are made by your department of the well cutting samples which you take?

The Witness: The well cutting samples that we collect are used for a number of purposes. Before we reach the gas pay the samples are used to determine exactly what formation we are drilling in so that we can set our casing in a well at a point as close to the pay formation as possible. After we have set our casing the samples that are used mainly to determine the formations in which we are drilling so that we can determine what formation we are in; so that we can determine when we go from one producing pay formation to another; so that we will know at what depth it is advisable to stop drilling a well; so that we can determine what formations we end the well in. Those are the main uses we make of our sample cuttings.

Mr. Spencer: Just one more question.

To what extent generally have you used well cuttings in making your determinations as to porosity of the formations encountered?

The Witness: I have used all well cuttings that I could obtain that showed porosity to get an idea of the relative porosities occurring in the well and to compare these cuttings and the occurrences of the bores with the cuttings obtained from oil wells where tests had been made which gave a general idea of what the average porosity might be.

By continually watching these samples I obtained a judgment of what the variability was and from the relative values reached an idea of what the average might be. It is mainly a relative form of getting a relative idea of porosities in the formations. It also gives an idea of how porous the rock looks in some of the big wells and things like that.

When we were drilling through some of the big gas pays at times I have been chased off the derrick merely by the shower of particles falling on the floor.

By Mr. March:

Q. You mean the flowing out of the gas? You mean the particles were blown out by the gas?
A. Yes, and we picked them up.

Peterson further testified (Vol. 69, pp. 10104-10120) as follows:

Mr. March: I'll repeat it.

Q. Do you know of any other gas field to your knowledge that has as good a record as this field in regard to dry holes—gas field, I am speaking of now?
A. Well, let's see, that's 104 dry holes out of approximately 1600 gas wells. That would be about 1/16th. I am not certain, but I think the Homer field has a better record than that.
Q. Where is that?
A. Down in Louisiana.
Q. You don't know about that, though, do you?
A. That's the trouble with the question. You would have to make a study of all these fields to know exactly what the percentage of the dry holes was.
Q. About what is the percentage, do you know, down there?

The Trial Examiner: You mean this field in Louisiana that he mentions?

Mr. March: That's right.

The Witness: That's the trouble, I'm not certain. He is asking me to try to compare this field with all the fields in the United States and I will have to admit I don't know how to do it without doing a lot of reference work.

Mr. March: All right.

Q. Now, let's see, I notice a rather unusual thing about these dry holes, that there are very few of them in Canadian River acreage, is that correct? Do you understand the question, Mr. Peterson?
A. Yes, sir, that is correct.
Q. By the way, before we go any further, my question as to dry holes—did you include in your figure the abandoned gas wells, too, your 140 figure?
A. 104 was the figure I stated.

Q. Does that include—I was just asking you about your dry holes. I haven't got to abandoned gas wells yet. I want to be sure I got that figure.

A. From what I can make out, there are 103 dry holes. It might be 104, though.

Q. 103 as distinguished from your abandoned wells?

A. Yes, sir.

Q. I just wanted to get that clear. As I see here you only have two dry holes in the Canadian River acreage, is that right?

A. I don't show any dry holes here on Canadian River acreage.

Q. You don't?

A. No.

Q. Are there any?

A. Well, I think that they have some outside the boundaries of the field.

Q. We are talking about the field now—Canadian River has not drilled a single dry hole in the field, is that right?

A. I believe that is right.

Q. In other words, every time they put a well down they have got gas, is that correct?

A. Yes, sir.

Mr. Keffer: May I ask a question there, Mr. March?

Mr. March: Sure.

Mr. Keffer: I'll tell you what it is in advance—

Mr. March: Go right ahead, Mr. Keffer.

Mr. Keffer: Have there been any dry holes drilled, Mr. Peterson, on lands adjacent to Canadian River lands?

The Witness: Yes, sir. There have been two dry holes right adjacent to those.

By Mr. March:

Q. Who drilled those?

A. Texoma Natural Gas Company.

* * * * *

Q. How many wells has Texoma Natural Gas Company, approximately?

A. About 165 wells.

Q. Only two dry holes. Do you know of any company

in the Panhandle field with the exception of the Canadian River Gas Company that has a better record as far as dry holes is concerned, than the Texoma Natural Gas Company, taking into consideration the number of wells drilled?

A. Well, I hate to say that. I really don't know.

Q. You don't know of any, do you?

A. No, sir.

Q. How many dry holes—strike that.

As I counted there are only 10 dry holes east of the County line of Hutchinson County and Carson County here—pardon me, west of the County line of Hutchinson and Carson counties, in the gas producing formation. I mean by that, as I count the dry holes here in the entire eastern portion of the field—the western portion of the field, the portion west of the east line of Hutchinson and Carson Counties in the gas producing portions of the field, I don't believe there are but 10 dry holes there, is that correct?

A. West of the east line of Carson County in the west gas field?

Q. That's right.

A. I haven't tried to pick the dry holes in the oil area.

Q. I am talking about commercial gas acreage.

A. I think that is correct.

Q. I notice you counted one up here in the oil acreage. Is that oil acreage that dotted line coming up in—

A. It is close to the line there. I thought it was right on the line there.

Mr. Lange: In Hutchinson County?

The Witness: In Hutchinson County.

By Mr. March:

Q. That is approximately correct, isn't it?

A. I think that is correct.

Q. You wouldn't have any difficulty in saying that you didn't know of a field in the history of this country that had a better history as far as dry holes, just taking the dry holes? Could you make a statement like that without any fear that you were making an incorrect statement, to your knowledge?

A. No, I don't believe I do.

Peterson further testified (Vol. 82, pp. 12214-122[illegible]) as follows:

Did you know there are some 80 wells located in the Borger-Lefors area in which pressures have been increasing—have increased since 1935?

A. I have an impression that there are some wells in that area in which the pressure is increasing but I haven't made a study of the exact number.

Q. Do you know?

A. But I haven't made a study of the exact number.

Q. Do you have any idea as to what percentage of those wells you used in calculating your pay thickness?

A. Not having made a study and not knowing what wells the pressure is being increased in, I have no way of telling how many of those I used in my pay thickness.

* * * * *

Q. And you stated in your cross examination this morning, except for very isolated instances your marginal area was controlled to a great extent by the open flows that you found in that area, did you not?

A. Yes, sir.

Q. Did you take into account structural conditions where your wells—where not many wells had been drilled?

A. Yes, sir.

Q. All right, will you state the average open flow which you found in the gray area?

A. I have this worked out for the different divisions of the gray area. For Carson County west field, sweet gas area, the average 430-pound natural open flow was 2,900,000 cubic feet. This was from seven wells which had a total 430-pound open flow of 20,300,000 cubic feet.

In the Gray County west field, the sweet gas area, the average 430-pound open flow was 3,018,000 cubic feet. This took into consideration 28 wells, 11 of which were dry holes.

The Trial Examiner: You mean by that, Mr. Peterson, you included 11 dry holes in your average?

The Witness: Yes, sir, to give an idea of what the area might have.

The Trial Examiner: As I take it now you are arriving at the average open flow of the wells in that area?

The Witness: I have to count the dry holes in as an open flow of zero, because they show a bad condition.

The Trial Examiner: I see. Very well.

The Witness: Now, in Moore County west field, sweet gas area, there was a very small area, and the only thing near this area was a dry hole.

In Potter County west field, the sweet gas area, it had one well with 430-pound open flow of 4,100,000 cubic feet.

In Carson County, west field, sour gas area, the average 430-pound flow was 4,720,000 cubic feet. This was obtained from five wells, including one dry hole.

In the Gray County west field, sour gas area, the average 430-pound open flow was 1,615,000 cubic feet.

In Hartley County, west field, sour gas area, the average open flow from two wells was 3,500,000 cubic feet, while the open flow from another well was 10,600,000 cubic feet, which is in my opinion representative of a small part of the area.

In Hutchinson County west field, sour gas area, the average 430-pound open flow was 3,373,000 cubic feet. This was taken from a total of 11 wells and included no dry holes.

Considering three additional dry holes, the average 430-pounds open flow in this area would be 2,650,000 cubic feet.

The Moore County west field sour gas area had an average 430-pound open flow of 3,583,000 cubic feet. This included 10 wells and included no dry holes.

The Collingsworth county east field, sweet gas area, had an average 430-pound open flow of 2,038,000 cubic feet. This was from two wells.

Testimony of J. D. Thompson, Jr.
Witness for Canadian.

J. D. Thompson, Jr., witness for Canadian, testified with respect to gas reserves in the Texas Panhandle Field (Vol. 6?, pp. 9965-9973) as follows:

A. "My name is J. D. Thompson, Jr. I was born in

Johnstown, Ohio, January 31, 1891. I now live in Amarillo, Texas.

"I graduated from Denison University, Granville, Ohio in June, 1914, receiving the degree of Bachelor of Science, my major subject being geology. After receiving my degree I spent approximately two years doing graduate work at Cornell University in Ithaca, New York. My work there was largely confined to advanced courses in Geology but also included duties as instructor in laboratory work offered to the under-graduate students by the department of Geology. My work at Cornell University extended over the period from September 1914 until April 1916, at which time I took a position as field geologist for the Empire Gas and Fuel Company at Bartlesville, Oklahoma. I have practiced my profession as oil and gas geologist continuously since April 1916 to the present time.

"I was employed by the Empire Gas and Fuel Company for a period of three years during which I did field work in Ontario, Canada, New York State, Pennsylvania, Ohio, Indiana, Missouri, Illinois, Kansas, Colorado, Oklahoma, Louisiana and Texas. My work for the Empire Gas and Fuel Company was varied and may be best described under three headings.

"1. Plane-table surveys in which I did detailed mapping of structural geology as shown by rock beds outcropping on the surface of the earth.

"2. Reconnaissance work in which I scouted ahead of the plane-table crews searching for areas in which favorable conditions of structural geology were present. Upon my recommendation such areas would later be mapped in detail by the plane-table crews.

"3. Subsurface structural geology work in the oil and gas fields of Northern Louisiana. In areas such as this last one mentioned, where surface outcroppings of the rock beds offer only meager information as to the structural condition existing below the surface of the earth, the structural geology of the area is worked out by a study of the logs and sample of the drill cuttings of the wells drilled in the area. This is known as subsurface work.

"In the spring or summer of 1919, I resigned from my position with the Empire Gas and Fuel Company and took up work for Mr. Leroy Adams, an independent oil operator with headquarters at Wichita, Kansas. My work for him included both detailed surveys and reconnaissance work in Kansas, Oklahoma, Wyoming, Montana, Ohio, Kentucky, Mississippi, Alabama, Tennessee, Georgia and Florida.

"In April 1922, I moved to Amarillo, Texas, where I took a position as district geologist in the Texas Panhandle area for the Gulf Oil Corporation, which was then known as the Gulf Production Company. I was employed by them continuously for seven years until the summer of 1929. My work for this company may be divided into three phases.

"The first phase may be called exploratory work which covered a period from the year 1922 until the year 1926. At the time I took up my work in this area, only two oil wells located in northern Carson County and some 20 to 25 scattered gas wells had been completed there The production from the two oil wells was being pumped into steel storage tanks since there was no oil pipe line leading from the field at that time.

"Of the gas wells a group of perhaps ten or fifteen in Potter and Moore Counties were being operated by the Amarillo Oil Company which had built a pipe line to the city of Amarillo where it furnished gas for commercial and domestic use. The remaining gas wells were connected only for use as field fuel for the exploratory operations going on at that time.

"During the four years 1922 to 1926, my work included a study of the subsurface geology of the Texas Panhandle area. In this period many exploratory test wells were being drilled in widely scattered locations throughout the Texas Panhandle area. The results of these tests and a study of the well records and samples of the drill cuttings obtained from them revealed the fact that the Texas Panhandle oil and gas field was confined to and controlled by a very large anticlinal structure or upward fold in the rock beds having an axis extending from southeast to northwest through Wheeler, Gray, Carson, Hutchinson, Potter, and Moore Counties, Texas, for a distance of more than 100 miles

"This anticlinal structure was found to be underlain by an irregular range of mountains composed of igneous rock upon which had been laid down sedimentary rock beds of Pennsylvanian and Permian age. These sedimentary beds included several irregularly distributed pay formations containing oil and gas and salt water. Along the apex of this fold, gas has accumulated in tremendous quantities; while along its northeast flank and in local low areas near its apex and on its southwest flank large concentrations of oil are found in the several pay formations which produce gas higher on the structure. Lower on the anticlinal structure, down dip from the oil producing area, salt water was encountered in the pay formations.

"Wells encountering salt water instead of oil and gas are called dry holes by oil and gas men. The extent of the field was defined by the salt water wells occupying a low structural position around the margins of the field. During this exploratory period, the Gulf Oil Corporation extended their lease holdings in this area on my recommendations until they included approximately 200,000 acres. Also upon my recommendations they drilled several exploratory test wells and contributed money or material to the drilling of many more scattered throughout the field.

"The second phase of my work in the Texas Panhandle oil and gas field may be called development work. It followed immediately after the exploration phase already discussed and covered the years 1926 to 1927. At this time oil pipe lines were built to the Texas Panhandle field connecting it to the trunk pipe line systems of the larger oil companies and hundreds of oil and gas wells were drilled in this field.

"During this period, the Gulf Oil Corporation completed between 150 and 200 oil and gas wells there and it became my duty to furnish geological information to guide the drilling and production department in the completion of these wells. This work included recommendations as to the proper points at which to set casing in the wells and the furnishing of information as to the probable depths at which gas, oil and salt water might be expected in order that the completion of the wells should be as efficient as possible. My work also included the making of recommenda-

tions as to the locations of wells drilled in semi-proven areas within the field. This work was undertaken to avoid as much as possible the drilling of dry holes and also gas wells which could find no market connections at that time.

"My work during both the exploratory phase and the development phase necessitated that I keep constantly in touch with the drilling activities of all operators in the field, in order that I might keep abreast of current additions to geological information that would be of practical value in guiding the program of the Gulf Oil Corporation.

"The third phase of my work for the Gulf Oil Corporation may be referred to as the geophysical phase. During the years 1928 and 1929 I was given the assignment of correlating the subsurface geology of the Texas Panhandle and of West Texas with geophysical exploration work which was being carried on by them at that time. This included a magnetometer survey which covered almost the entire area from the north line of the Texas Panhandle region southward into southwest Texas. In doing this work, it was again necessary for me to study the logs and samples of the drill cuttings secured from the many test wells scattered throughout this large area.

"In August 1929 I resigned my position with the Gulf Oil Corporation and opened an office as independent consulting geologist. Since that time I have been engaged continuously in doing consulting work on geological problems in connection with oil and gas. I estimate that approximately 95 per cent of this work has been confined to the Texas Panhandle area.

"My work as a consulting geologist in this area covers various activities.

"I am called upon to make locations for oil and gas wells and for recommendations as to casing points and drilling depths of these wells.

"I frequently prepare valuation reports on oil and gas properties. Such reports are used by prospective buyers of such properties or owners who wish to make sales of such properties or banks who make loans on them. My valuation reports are also required by individuals or estates owning

oil and gas properties in connection with their income taxes or estate taxes.

"I also prepare appraisals for the use of corporations in their reports and applications to the Securities and Exchange Commission in connection with matters of financing stock or bond issues.

"My work also includes the preparation and presentation of technical evidence before various commissions and courts of law as to conditions existing in the Texas Panhandle oil and gas field.

"In order that I may carry on this varied work and be of service to my clients I must of necessity keep an up-to-date file on the development activities of the field. At the time I left the Gulf Oil Corporation in the year 1929, they were kind enough to give me a complete file of information on all the wells drilled in the Texas Panhandle field up to that time. I subscribe for the services of the Dwight Well Log Service of Amarillo, Texas, from whom I obtain copies of logs of all the wells drilled in the field. This I supplement with information obtained from many of the operators in the field, including both independent operators and major oil and gas companies. This includes information on oil and gas production and the geology of the field. Some of the geological departments of the major oil companies maintain collections of samples of the drill cuttings from most of the wells in the field. I have access to these collections and have examined thousands of well cuttings from wells in all portions of the Texas Panhandle field in connection with my study of the geology of the area.

"I might explain that these samples of well cuttings are taken from the wells at regular depth intervals, usually every five or ten feet, and put in little cloth bags which are labeled with the name of the well and the depth from which the samples came. These bags of samples are brought to the geological department of the oil or gas companies, where they are washed, dried and put into one-ounce bottles. These bottles are labeled as to the name of the well and the depth of the samples, and aranged in boxes in proper sequence from the top to the bottom of the well. Examining these, one can get at a glance a quick picture of the formations

which any particular well penetrated, or one can make a detailed microscopic study of the whole geologic section as revealed by these samples of the drill cuttings.

"These samples are accessible to me partially by virtue of my personal friendship with the geologists of the major oil and gas companies. However, I am able to cooperate and contribute to them information and samples from the wells drilled in the field by numbers of my clients. In many cases small independent operators do not keep collections of drill cutting samples, but are willing to instruct their drillers to take the samples as the wells are being drilled, sack them and mark them properly and turn them over to me or the scouts or geologists of the major companies who maintain a sample exchange so that all of the companies cooperating may obtain samples not only from their own wells but from any other wells in the field which are of particular interest to them. The sample exchange bureau referred to is managed by E. V. Dwight, who has headquarters in the Herring Hotel, Amarillo, Texas."

The witness then identified Exhibit 187 which was received in evidence, and which is a pressure contour (isobar) map of the Texas Panhandle Field, the various pressure bands of which are set out in different colors.

The witness explained that the heavy line around the outside of the map represents the outline of the Texas Panhandle Gas Field as determined by the Railroad Commission of Texas. There are some additional areas included along the northeastern flank of the colored portion of the map which produce oil, but which are not considered as part of the gas field. The colored pressure bands represent 20 pound differentials in pressure.

The witness further explained the map, Exhibit 187 (Vol. 68, pp. 9976-9987), as follows:

"Introducing Exhibit No. 187, entitled 'Texas Panhandle Gas Field Rock Pressure Map, May 1939.'

"This exhibit portrays the extent of the Texas Panhandle gas field. Its border is outlined by heavy black lines as drawn by employes of the Railroad Commission of Texas on a map issued by them in the summer of 1937. Nothing has occurred in the development of the field since that time which materially changes this outline and it will serve our present purposes in defining the extent of the field.

"This exhibit further portrays by 20-pound interval contours and colored bands the rock pressure conditions existing in the Texas Panhandle field as of July 31, 1939. I drew these contour lines and colored bands, using the official well-head gauge pressures recorded by the Railroad Commission of Texas during the summer of 1939, purporting to show the rock pressure conditions existing in the field as of July 31, 1939.

"The following legend is used, as indicated on the exhibit, each color representing well-head gas pressure conditions as follows:

	Pounds
Gray	0-200
Orange	200-220
Dark Blue	220-240
Pink	240-260
Red	280-300
Purple	300-320
Yellow-Green	320-340
Light Blue	340-360
Brown	360-380
Salmon Pink	380-400
Yellow	Above 400

"It will be noted that the area colored gray, where well-head gauge pressures are 200 pounds or less, are confined to or are adjacent to those portions of the field which produce oil; while the areas colored yellow, where well-head gauge pressures are 400 pounds or above, are situated in localities remote from the oil producing portion of the field."

Q. Right there, Mr. Thompson, you might explain by reference to the map where the oil producing formations in the field are.

A. Most of the oil producing portions of the field lie on the northeast side of the field with unimportant exceptions, such as east central Carson County where there are two oil wells and a few down in south central Gray County.

Q. You have a number of little dots on the map, Exhibit 187, both within the gas field area and without the gas field area. What do those dots represent?—all up and down the northeast flank of the structure there.

A. Those dots represent oil wells. Also I call your attention to the fact that there is an area in northern Moore County which produces some oil.

Q. You say those dots represent oil wells. Do those dots within the confines of the gas field also produce gas as well as oil?

A. Yes.

Q. All right.

A. "Originally, the entire area of this field had a pressure of 430 pounds and would, therefore, have been colored solid yellow, using the above color scheme. The pressure differential in the field, as indicated on this exhibit, is the result of progressive depletion of the gas reserves of the field due to gas withdrawals coincident with the production of oil and gas withdrawals for gas pipe line use.

"In the early life of the field, gas was largely regarded as a nuisance, handicapping the development of oil production. Since there was no market outlet for the gas itself, the result was that it was wasted in tremendous quantities during the early production history of the field. The earliest major oil producing areas to be developed in the field were the Borger area in south-central Hutchinson County and the Lefors area in central Gray County.

"In these two areas, gas was encountered in pay formations above the oil bearing formations. Little interest was taken in conserving this gas. It was frequently allowed to flow from the hole along with the oil and was, thus, entirely wasted to the air. This gas produced with oil was known as casinghead gas.

"This situation gave rise to what is now known as our casinghead gasoline industry in this field. The otherwise wasted gas could be utilized by casinghead plants which removed its gasoline content and popped the residue gas

into the air. Since enormous amounts of gas were thus being wasted, the carbon black industry then moved into the field to utilize the otherwise wasted casinghead gasoline plant residues for the manufacture of carbon black.

"These two industries were, therefore, firmly established and used tremendous quantities of gas from the oil producing areas of the Texas Panhandle field before the major gas pipe lines were ever built to convey gas to distant cities for industrial and domestic use. The result of these early withdrawals from the oil field areas was the establishment of the pressure differential picture set forth in this exhibit. Without question, there has been a tremendous drainage of dry gas from that portion of the field which produces dry gas only to the low pressure oil producing areas due to this long-established differential in pressure. That drainage has continued progressively from year to year and is effective today.

"Estimate of Reserves.

"Introducing Table A of this exhibit entitled:

"Estimated Original Recoverable Reserve of the Panhandle Field at a Pressure Base of 16.4# per square inch at Assumed Wellhead Abandonment Pressures of 0, 25, 50, 75, 100 and 125 Pounds.

"In arriving at my estimate of the original gas reserves of the Texas Panhandle gas field, I have assumed that the estimate of the Railroad Commission of Texas of 1,461,936 acres for the total proven gas acreage in the field is substantially correct. I have divided this gas acreage into two classes:

"Commercial	1,035,146 acres
"Marginal	426,790 acres
"Total	1,461,936 acres

"Mr. C. J. Peterson's Exhibit No. 206, shows substantially my ideas as to the location and extent of these two

classes of gas acreage in this field. This exhibit expresses so nearly my own ideas in this matter that if I prepared a map myself setting forth my ideas on the subject, it would be so nearly a duplication of Mr. Peterson's map that I do not consider it worthwhile to do so.

"Estimate of Gas Reserves:

"Following is my estimate of the original gas reserves of the Texas Panhandle gas field at zero pounds absolute:

Commercial—1,035,146 acres at 17,514 Mcf. equals 18,129,547,044 Mcf. at 0# Abs.

Marginal—426,790 acres at 5,000 Mcf. equals 2,133,950,000 Mcf. at 0# abs.

Total—1,461,936 acres 20,263,497,044 Mcf. at 0# Abs.

"In estimating the gas reserves of any field, one of two methods is generally employed by geologists and engineers.

"One, usually referred to as the 'pressure decline' method, makes use of data setting forth rock pressure declines as compared to total withdrawals. This method is very satisfactory for use in estimating the reserves of small fields in which the thickness and porosity of the pay formation is comparatively uniform. However, it cannot, in the writer's opinion, be used with any degree of satisfaction in the Texas Panhandle gas field which involves an area of nearly 1,500,000 acres under which the porosity and thickness of the pay formation are exceedingly variable.

"Another method, therefore, has been applied by the writer in determining reserves of gas in this field. This method, known as the 'pressure porosity' method, takes into account the volume of effective pore space in the reservoir rock, as indicated by estimated pay thickness and porosity conditions.

"'Commercial Gas Acreage

"In arriving at the estimated gas reserves under the class of acreage referred to as 'commercial acreage,' the following formula has been used:

$$\frac{43560 \text{ x } 471 \text{ x } 70 \text{ x } 20 \text{ per cent}}{16.4} = 17{,}514 \text{ Mcf. gas per acre.}$$

"In the above formula.

43560 equals Number of square feet in one acre.

471 " Average original bottom hole pressure expressed in pounds per square inch.

(430 plus 13 plus 28 equals 471)

430 equals Original well head gauge pressure.

13 equals One atmosphere at barometric reading of average atmospheric pressure of field in pounds per square inch.

28 equals Weight of column of gas in pounds per square inch. (Bureau of Mines Formula).

70 equals Average feet thickness of pay formation in field.

20 per cent equals Average porosity of pay formation in field.

16.4 equals The pressure base expressed in pounds per square inch at which the gas is measured.

"To arrive at the average pay thickness of 70 feet, indicated above, a study has been made of hundreds of well records from gas wells in the field.

"The average porosity of 20 per cent is the result of studies made by myself and other geologists in this and other gas fields.

"Marginal Gas Acreage

"Experience to date forces me to conclude that as a whole the marginal area of the Texas Panhandle gas field is underlain by comparatively thin gas pay formations of low permeability and I seriously question the economic expediency of attempting any wide-spread drilling campaign there.

"This marginal gas area includes that portion of the field where I anticipate that wells of less than 5,000 Mcf. natural open flow volume capacity would be completed if drilled. A study of the completion data obtained from the records of the wells drilled in the marginal area to date reveals that

they were either very small gas wells or dry holes, with the exception of a few instances where small oil wells were completed. Considering the information obtained from the records of these wells, I am forced to conclude that the marginal area is one of very low potential gas productivity where perhaps only two or three million cubic feet of gas per acre will be found. However, since information is rather incomplete in certain portions of this area due to lack of drilling, I have assigned a judgment figure of an average of 5,000 Mcf. of gas per acre to the reserve of the marginal area. This, I am confident, makes due allowance for instances where possible future exploratory drilling may result in encountering larger open flow volumes than I anticipate at the present time.

"The pressure factors shown in Column 3 on Table A of this exhibit are arrived at by the application of a formula worked out by the United States Bureau of Mines and published on Page 167 in 'Bureau of Mines—Monograph 7,' together with Table 37, Page 156 of the same publication. By this formula, the following ratios between gas at zero pounds absolute and the various assumed well-head gauge abandonment pressure in this field are shown as follows:

Pressure factor for 0# well-head gauge $=1-\frac{14}{471}=.97028$

(14 = bottom hole pressure when well-head pressure = 0)

Pressure factor for 25# well-head gauge $=1-\frac{40}{471}=.91507$

(40 = bottom hole pressure when well-head pressure = 25)

Pressure factor for 50# well-head gauge $=1-\frac{67}{471}=.85775$

(67 = bottom hole pressure when well-head pressure = 50)

Pressure factor for 75# well-head gauge $=1-\frac{94}{471}=.80042$

(94 = bottom hole pressure when well-head pressure = 75)

Pressure factor for 100# well-head gauge $=1-\frac{120}{471}=.74522$

(120 = bottom hole pressure when well-head pressure = 100)

Pressure factor for 125# well-head gauge $=1-\frac{147}{471}=.68790$

(147 = bottom hole pressure when well-head pressure = 125)

(When well-head gauge pressure = 430 pounds, the bottom hole pressure = 471 pounds)

"It will be noted that Column 5 on Table A of this exhibit indicates that I have used a recovery factor of 90 per cent. It is generally recognized by geologists and engineers that a 100 per cent recovery of the gas from any given field is impossible. I believe that the use of a recovery factor of 90 per cent in estimating the recoverable reserves of the Texas Panhandle gas field is entirely justified.

"The tremendous area of the field and the extreme variation of conditions in the pay formations must be taken into consideration.

"Incomplete recoveries of gas from the field may be anticipated for various reasons which include the trapping of gas in pay lenses, water pollution from both bottom hole water and upper water improperly shut off due to imperfect casing.

"The plugging of wells by salt precipitation, the rusting through of casing or any other occurrences leading to insurmountable mechanical difficulties, will also contribute to incomplete recovery of gas from the field.

"Contributing to incomplete recovery of gas from the field is the fact that at any given well-head abandonment pressure of the wells in the field a higher pressure will exist at points between the wells. This being the case, the gas creating this higher pressure between the wells will not be recovered at any assumed well-head abandonment pressure. For example, when the wells in the field have reached a pressure of 125 pounds, it is reasonable to assume that some areas in the field between the wells might have a pressure of 150 pounds or 175 pounds or higher, representing a substantial volume of unrecoverable gas should the field be abandoned at 125 pounds well-head pressure. A like condition would exist, relatively speaking, at any other assumed abandonment pressure.

"It is reasonable to assume that large portions of the marginal area will never be drilled due to the fact that such development would be economically inexpedient because of the small open flow volume capacities to be anticipated in the drilling of wells in this area. The result will be a very much wider well spacing in the marginal area than in the com-

mercial portion of the field, resulting, obviously, in incomplete recovery of the gas reserves of the marginal area. This effect will be increased by the low permeability which our experience indicates to be existent in the marginal area.

"It will be noted that Column 7 on the exhibit sets forth total production from the Texas Panhandle field to the date January 1, 1939. Mr. Peterson's Exhibit No. 206 explains the method of arriving at this figure."

The witness further testified (Vol. 69, pp. 9990-9991) as follows:

A. Presenting Table "A" in exhibit 207. "Estimated Original Recoverable Reserves of the Panhandle Field at a Pressure Base of 16.4# per square inch at assumed wellhead abandonment Pressures of 0.25, 50, 75, 100 and 125 Pounds.

Assumed Abandonment Pressures	At 0 Lbs. Abs.		Pressure Factor	Product		Recovery Factor		Original Recoverable	Production to 1-1-39	Recoverable 1-1-39
0# Gauge	20,263,497,044	Mcf.	x .97028	19,661,265,912	M	x .90	equals	17,695,139,321	7,156,238,820	10,538,900,501
25# Gauge	20,263,497,044		x .91507	18,542,518,240	M	x .90	"	16,688,266,416	7,156,238,820	9,532,027,596
50# Gauge	20,263,497,044		x .85775	17,381,014,589	M	x .90	"	15,642,913,130	7,156,238,820	8,486,674,310
75# Gauge	20,263,497,044		x .80042	16,219,308,304	M	x .90	"	14,597,377,474	7,156,238,820	7,441,138,654
100# Gauge	20,263,497,044		x .74522	15,100,763,267	M	x .90	"	13,590,686,940	7,156,238,820	6,434,448,120
125# Gauge	20,263,497,044		x .68790	13,939,259,617	M	x .90	"	12,545,333,655	7,156,238,820	5,389,094,835

On cross examination the witness (Thompson) testified that the reserve estimate which he had given could not be called either a maximum or a minimum estimate but that he did think it was a fair estimate and one that he thought was right; that he could have done several things that would have made a smaller estimate, for example, he could have used a higher recovery factor but he did not do so because he did not think it was justified and neither did he think a lower recovery factor would be justified, and that if he had thought so he would have used a lower recovery factor. He used the recovery factor that he thought was right. The witness does not think that, rationally, he could have made the estimate either higher or lower. (Vol. LXXV, p. 10972, 10973.)

The witness further testified that open flow of the wells was a good criterion of the relative amounts of gas in place and that although he did not do so, it was not unreasonable to estimate reserves on the basis of open flow of the wells because sustained high open flows indicated a high porosity. (Vol. LXXVI, p. 11153, 11154.)

The witness testified on cross examination that he was likely too generous in his estimate as to the gas in place in the marginal area and that the structural situation in such area was such that to him it was unthinkable that that area contained much gas. (Vol. LXXVI, p. 11140.)

The witness was then referred to the marginal area (colored gray) on Peterson's map contained in Exhibit 206, in Moore County, where only a few wells had been drilled, and was asked if that area would probably not prove to be highly productive. The witness answered that he had rather definite information about the structural situation in the particular area referred to and that it was going to be too low to be highly productive, but on the other hand that he had assigned a higher acre content to the marginal area to take care of a situation where larger wells might be discovered. That some wells near the edge of the field are highly productive because they are far enough up on the struc-

ture to make them so, but there is a sudden rapid dip in the producing formations at the edge of the field. Experience through the history of the field has indicated that you will run out of high productivity almost immediately. (Vol. LXXVI, pp. 11141-11143.)

Witness further testified that the marginal or gray area, as shown in Exhibit 206, in Moore County, was generally low structurally and that this had been determined from geological information from small wells drilled within the area as well as dry holes drilled outside of the area and that although large wells are sometimes found near the edge of the field and near the edge of the gray area, because they are located rather high structurally, still these wells do not indicate that the marginal area generally has large gas reserves because its structural position is too low for this to be true.

(Vol. LXXVI, pp. 11142-11148.)

On cross-examination the witness testified that it was still necessary to apply a recovery factor, even though the field was not producing down to zero pounds wellhead. In other words, wherever you stopped producing, whether at 25 pounds wellhead or any other figure, there would always be areas in the formation between the wells higher in pressure than the abandonment pressure at the wellhead. (Vol. LXXV, pp. 11096-11098.)

The witness also reiterated the statements contained in his direct testimony with respect to loss of gas through mechanical troubles, such as caving or salting up of the formations and many other things that can happen to gas wells, which would dry up the outlets and result in the non-recovery of gas which would otherwise be recovered by the well, all of which would make it impossible to obtain a 100 per cent recovery. (Vol. LXXV, p. 11108.)

The witness, upon being cross-examined on an assumed 25 pounds abandonment pressure, testified that at this abandonment pressure you would have approximately 6 per cent of the original gas left in the reservoir but that this assumes that you had an equal pressure of 25 pounds all over the

field, not only at the wellhead but back away from the wellhead where it is known there would be substantially higher pressures and that the gas represented by those substantially higher pressures would not be recovered if the wells in the field were abandoned at 25 pounds. There must be something deducted from the total reserve in order to get the recoverable figure which calls for the application of a recovery factor at any assumed wellhead abandonment pressure. The witness then referred to an estimate of reserves as shown in Schedule A, Exhibit 207, wherein he arrived at a figure of 18,542,000,000,000 cubic feet plus, which is absolutely all the gas there is in the field above an assumed 25 pounds abandonment pressure. He then stated that you would not get every foot of that gas because there will be pressures in the field that will be substantially higher than the 25 pounds at the well, and therefore this calls for the application of a recovery factor. (Vol. LXXV, pp. 11101-11104.)

The witness also testified that in some fields which were influenced by water drives and where the encroachment of water causes the blocking off of large amounts of gas, recovery factors as high as 40 or 50 per cent are sometimes used and that although he did not anticipate any great loss of recovery on account of water in this field (Texas Panhandle Field), still there would be local losses due to water pollution from wells but not nearly as great as is encountered in the water-drive field, and also that although there were many reasons why all of the gas would not be recovered at any given abandonment pressure that one of the most important reasons is the fact that the gas pressure will always be higher out in the formation between the wells than it is at the well. (Vol. LXXV, pp. 11107, 11108.)

The witness discussed also the matter of bottom hole water and that as pressures go down water encroachment will become a great deal more important and also as the equipment in the wells gets older water troubles will develop to a more serious proportion. All wells reaching low pressures will not eventually develop water troubles but the water that is included in the field will probably be more operative in low pressures than in high pressures and water encroachment probably more effective as pressures get lower. (Vol. LXXV, pp. 11111-11113.)

Determination of Thickness of Gas Pays

The average pay thickness of 70 feet in the best commercial area of the field was utilized by witness in making his computations as to reserves and was based upon a study made by him of hundreds of gas wells in the field. (Exhibit 207, p. 8, Vol. LXVIII, p. 9983.)

The witness on cross-examination stated that he had used nearly 600 wells in determining his average pay thickness. (Vol. LXXV, p. 11034.) The determination was made in the early part of 1938. The figure arrived at for the average of all wells utilized was 69.86 feet but for convenience in computing his reserves he considered the pay thickness to be 70 feet. Pay thicknesses cannot be determined exclusively from well logs. The card index file kept by witness and which was utilized by him contains more information frequently than do the wells logs. (Vol. LXXV, pp. 11035-11036.) Witness explained how a determination of pay thickness was made from a study of well logs and from information he had gathered from time to time and shown on his card index system, and where these two sources of information were not clear, by discussing the matter with drilling superintendents, drillers on the rig and others who might have definite information about a particular well. With all of this information assembled it is then a matter of taking the pay formations in which gas was encountered and the distance of each formation in which gas was encountered, and totaling them up in order to get the total pay thickness for any given well. (Vol. LXXV, pp. 11041-11050.)

The witness was cross-examined at length regarding numerous wells with respect to the data contained on the cards taken from his card index file, and from the information shown on these cards the witness computed the pay thickness in a number of wells. He then stated on redirect examination that he could not hope to, and did not attempt to, keep all of the relative information with regard to pay thickness or other matters readily accessible in his cards, but that he did try to keep a card on every well drilled in the field, although there were some wells upon which he did not have cards, but these cards merely represented the beginning point of his investigation of any particular well, whether for pay thickness or any other matters; that he did not rely

entirely upon his card index file, nor upon wells logs for determining pay thicknesses or other matters, but gathered all information he possibly could from reliable sources available to him. (Vol. 94, pp. 14357-14362.)

The witness did not consult with Peterson with respect to his pay thickness determination except as to some wells of Texoma Natural Gas Company, the drilling of which had been supervised by Peterson. (Vol. LXXV, p. 10964.)

Thompson stated on direct examination that in the Texas Panhandle Field natural gas occurs in four separate geological formations, as follows:

1. Red Bed, which is of negligible importance.
2. Brown Dolomite, which is by far the most consistent and important gas pay in the field.
3. White Lime, which is of relatively small importance.
4. Granite Wash, which is locally quite important, but is not consistent in its occurrence in productivity and does not cover nearly as large an area as does the Brown Dolomite gas pay.

In order to portray the great variability of conditions under which oil, gas and water are found in the Texas Panhandle area, the witness prepared two graphic cross sections showing conditions found in the various wells included in said cross sections. These cross sections are marked Exhibits 208 and 209 respectively.

Exhibit 208 extends approximately from south to north through the lease holdings of Canadian, and Exhibit 209 extends from a point near the western end of the gas field through the lease holdings of Canadian. Their exact positions in the Texas Panhandle Field are shown on Exhibit 187 by green lines connecting the various wells shown in the cross sections.

These two exhibits are described in detail at pages 11 to 22 inclusive on Exhibit 207 and also in Volume LXIX, pages 9993-10019.

Briefly, these exhibits show the producing formations in the wells designated in each of the exhibits, and show the

respective formations in which gas, oil or water was encountered in those wells. They also show the type of gas pay formation in which oil, gas or water was encountered; that is, whether in Brown Dolomite, White Lime, Granite Wash or Red Bed. They also show the thickness of the gas pays encountered as determined from well logs and the card index file of witness Thompson, but do not necessarily show all of the information possessed by Thompson and utilized by him in the determination of sand thicknesses.

Thompson stated that there is extreme variability in the thickness and productivity of the various pay formations encountered and that one or more of these pay formations are absent in all of the wells shown. The cross-sections show that the Brown Dolomite gas pay formation is by far the most consistent and productive of any of the gas pays encountered.

Determination of Effective Porosity

On cross-examination witness reiterated that he had arrived at an average porosity of 20 per cent and that this figure was used in his reserve estimate. (Vol. LXXV, p. 11012.) It was his opinion that a 20 per cent porosity figure was the most accurate figure that could be reached. (Vol. LXXV, pp. 11053, 11054.)

Witness arrived at a determination of the average porosity through the examination of well cuttings, well logs, well cores, information that he could get from producers, etc. (Vol. LXXV, pp. 11001, 11002.)

Well cuttings are fragments of rock bailed out of the drilling wells—the samples of the cuttings can be bailed out when going through the gas pay if the open flow volume is not too great and cuttings are blown out of the hole from the gas pay in large wells. Sometimes big pieces of rock are blown out with good porosity in them. (Vol. LXXV, pp. 11002-11004.) Witness has examined a great many of the well cuttings under microscope (Vol. LXXV, p. 11010) and has examined many oil well cores under microscope covering a period of years. (Vol. LXXV, pp. 10995-10996.) The information obtained from the examination of oil well cores and the porosity determinations therefrom (Exhibits 216, 217; 218) has corroborated witness' previous ideas as to

porosity. Witness is permitted by the major oil companies to consult their collections of cuttings very freely at any time he desires. (Vol. LXXV, p. 11005.) The Gulf Oil Corporation, for example, had samples of well cuttings aggregating more than 250,000. (Vol. LXXV, p. 11009.) It can be determined where the cuttings are coming from that are blown out of the hole during drilling operations. (Vol. LXXV, p. 11006.)

Volume of Gas Produced from the Texas Panhandle Field from Beginning of Production to December 31, 1940.

Thompson did not utilize the gas withdrawal figures in his estimate of gas reserves. However, Schedule A of Exhibit 207 does show the production of gas up to January 1, 1939, which aggregates 7,156,238,820 Mcf. The witness deducted this figure from his original recoverable reserves at various assumed abandonment pressures in order to show the remaining reserves recoverable as of January 1, 1939.

Witness stated on cross-examination that he had accepted the Cotner and Crum figures of withdrawals (Exhibit 215) up to 1932, and as to subsequent withdrawals, had accepted Peterson's figures. (Exhibit 206, Vol. LXXV, p. 10975.) He accepted Cotner's figures because he had helped Cotner in the compilation of the figures and consulted with him very freely in the preparation of the Cotner paper, and he also knew the very great detail that Cotner went into in assembling his data and he was confident that his figures were approximately correct; and that such figures were accepted by the witness as the best available figures obtainable. In his opinion they could not be inaccurate enough to make any very great difference in the present remaining reserve estimate of the field. (Vol. LXXV, pp. 10977-10978.) The witness also testified that he had assisted Peterson in compiling his figures of withdrawals; that he knew that Peterson had spent a lot of time and very great care in the compilation of the figures and he was willing to accept them as being accurate. (Vol. LXXV, p. 10980.) He knew that it was necessary and that Peterson did convert some of the withdrawal figures from different pressure bases to a 16.4

pounds base, which is the base upon which the figures are given. (Vol. LXXV, p. 10987.)

The witness believes that you can estimate gas blown into the air with a fair degree of accuracy and he thinks Cotner did so. He was thoroughly familiar with the field and the witness has confidence that his work was sufficiently accurate that he does not hesitate to use it. (Vol. LXXV, p. 11094.)

J. D. Thompson, Jr., also testified (Vol. 75, pp. 10994-10998; 11013-11015; 11033-11037; 11085-11086; 11099-11105) as follows:

By Mr. March:

Q. Did you examine any such cores of the company?

A. No, sir.

Q. Is that a pretty expensive process, taking those kind of cores?

A. I presume it would be. I don't know much about it.

Q. Did you ever see one taken?

A. No.

Q. Did you ever see any kind of a core taken?

A. I think I have seen cores taken.

Q. Where was that?

A. In the Panhandle field.

Q. Oil well cores?

A. Yes.

Q. Did you ever see any gas well cores?

A. I don't believe I ever have.

Q. Do you know of anybody that ever has?

A. I don't recall having anybody tell me that they had.

Q. Where were these oil well cores from?

A. From various wells in the Texas Panhandle field. I can't specify any particular one.

Q. Could you specify a particular one if I gave you time to check up on it?

A. No.

Q. Did you examine those cores under a microscope?

A. Yes.

Q. Do you have a record of it?

A. No.

Q. About how many have you seen?
A. Oh, I wouldn't know. Over a period of years I have seen a great many but I couldn't say how many?
Q. About how many have you examined?
A. That is what I say, that I can't remember.
Q. You have no record of any examination of an oil core?
A. That is correct.
Q. Do you know the process by which the cores are taken, the different processes?
A. They use core barrels.
Q. That is not the most effective process, is it?
A. I am not an expert on the technique of taking cores.
Q. Do you know how to direct somebody to take a core?

Mr. Spencer: If he isn't an expert, I don't see how he could direct anybody.

Mr. March: He can say so.

Mr. Spencer: Why repeat the same question?

Mr. March: I want to be sure. I want to have it in the record just exactly how it is.

The Witness: No, I wouldn't attempt to direct anybody in doing that.

By Mr. March:

Q. Have you in your office a core of any well from anywhere?
A. I used to have two or three pieces of core. I don't remember whether I still have them or not.
Q. Were they of oil wells?
A. I don't even remember what wells they came from. I picked them up as showing certain conditions which were interesting to me. I presume they were from oil wells, however, they were not from the pay formation.
Q. They were not from the pay formation?
A. No.
Q. Did you look at them under a microscope?
A. I looked at them under a hand lens.
Q. Did you make any notes on your observations?
A. No.

* * * * *

Q. Can you take any given gas well and tell me what the porosity is in that gas well specifically?

A. That would be rather hard to do.

Q. How's that?

A. I don't believe I can.

Q. Have you any working papers where you have computed the porosity upon individual gas wells in the Texas Panhandle field?

A. No.

Q. Have you ever seen any such calculations?

Mr. Keffer: If the Examiner please, just on that—I don't know that it makes a whole lot of difference. Mr. Thompson explains in his exhibit very clearly and rather carefully the basis of reserves estimated in the field by him in which he takes as one of his factors a 20 per cent porosity throughout the commercial area in the field. There may be wells that have a greater porosity and there may be some others that have less. That is almost certain to be true. I think he has already stated that he made no calculations on individual wells in order to get that average, but that is determined by an examination of cuttings and all other information that he could get.

For that reason I feel as though the question has really been answered in his written statement so far as that is concerned.

Mr. March: I will proceed on—

Mr. Keffer: How's that?

Mr. March: I won't stay on that point any longer; however, I do want to explore it enough to know what it is.

Q. Now, Mr. Thompson, I note that you—you might answer my question. You might answer the question pending here. Have you ever seen any porosity determinations on individual wells in the Texas Panhandle gas field?

A. Yes.

Q. Whereabouts?

A. I have arrived at what might be called porosity myself by calculation.

Q. All right, can you tell me the porosity on any given well in the Texas Panhandle field?

A. No.

Mr. Spencer: Are you talking about gas wells?

Mr. March: He said no, that's all I want. Gas wells is what I'm talking about, yes.

Q. Now, let's see, now, have you ever seen anyone else arrive at the porosity of individual gas wells in the Panhandle field of Texas?

A. Yes.

Q. Who?

A. Peterson.

Q. Peterson?

A. Yes.

Q. Have you ever seen his tabulation as to porosity of individual wells?

A. Yes.

Q. Well, where is it?

A. I don't know. It isn't here, I am sure.

Q. That's the only one you have ever seen?

A. It is all that I recall at the moment.

Q. Sir?

That's all that I recall.

• • • • •

Q. I hand you a copy of Mr. Peterson's working paper and refer you to Page 10 and ask you if that is the well, Canadian River Gas Company Seay 1?

A. Yes.

Q. Will you give his thickness?

A. He gives a thickness of 52 feet.

Q. Now, Mr. Thompson, did you use this well in arriving at your pay thickness calculation?

A. I don't remember.

Q. Can you tell me any particular well that you used in arriving at the 70 per cent pay thickness?

Mr. Spencer: 70 what?

Mr. March: 70 feet pay thickness.

The Witness: I can't be absolutely certain.

By Mr. March:

Q. Well, have you a list of the wells that you used in determining your pay thickness?

A. No.

Q. There isn't such a list in existence?

A. No.

Q. How many wells did you use?

A. Nearly six hundred.

Q. There isn't any possible way for me to check upon the wells that you used?

A. No.

Mr. Spencer: How long ago did you do that work, Mr. Thompson?

The Witness: In 1938. In the early part of 1938.

By Mr. March:

Q. Did you then have notes on all these wells individually?

A. At the time I prepared the estimate I had a list of the wells which I assembled from my card file. I don't know that I had any further notes than that.

Q. Would you say that your 70.1 pay thickness that you arrived at was a pure judgment figure?

A. No. I didn't arrive at 70.1.

Q. What did you arrive at?

A. I arrived at 69.86, but I used 70 just for convenience. I think one must use his judgment in interpreting the pay thickness of the individual wells; so there is a judgment factor to that extent.

Q. You couldn't take the logs, then, of Canadian River and—driller's logs—another geologist couldn't go through them and get the same answer that you got just by looking at the logs?

A. I have explained to you that my card file on Canadian River carries a good deal more information than is contained on the logs. I found that the information on them was inadequate in a number of cases.

Q. So it wouldn't be safe to rely just on those logs and tabulate them as to pay thickness?

A. No, sir.

Q. Could you rely upon them in any case?

A. Now, just what case, for instance?

Q. I mean any particular case, any case. Just take those logs—suppose you take Canadian River's logs—could you rely upon them for any check?

Mr. Spencer: Any case or any purpose?

Mr. March: I mean in the case of any particular well or wells or logs.

Mr. Spencer: Rely upon them for what purpose?

Mr. March: I mean rely upon any of the well logs to determine pay thickness exclusively.

The Witness: No.

By Mr. March:

Q. So there is no way, then, that I can check your wells, your pay thickness calculations, is there?
A. No.
Q. Did you use the same wells that Mr. Peterson used?
A. No, I am quite sure I didn't.
Q. Well, do you have any idea of how may wells you used in common with him?
A. No.
Q. Would you say less than half or a third? Do you have any idea?
A. I have no idea. I never compared my list with his.
Q. Then you couldn't say whether you used any in common with him, could you?
A. I presume we must have. I know that I used a good many of the Texoma logs or pay thicknesses in Texoma wells, because I considered my information upon them was more accurate than on some of the other wells.

The Trial Examiner: Mr. Thompson, did you say that you have never compared your list with Mr. Peterson's? I thought you testified you had no list.

The Witness: I don't have at this time.

The Trial Examiner: I see.

The Witness: I made a list but I never compared my list with his.

By Mr. March:

Q. The list is non-existent today?
A. That is right.

* * * * *

By Mr. March:

Q. Isn't one of the most productive areas of the Canadian River Gas Company near the Fritch compressing station?
A. There are some very good wells in that area.
Q. I note that around that area we have pressures of 346, 345, and 342.
A. That appears to be about right.
Q. Now, that being true, the pressures being down considerably there, what makes you conclude that just because the pressures are down in these wells, these oil wells which have penetrated the gas pay in which wells the gas is cased off, that the production is depleted—I mean, the gas is depleted?
A. The original reserve existing in that area has been depleted by the loss of pressure in direct proportion to the loss in pressure.
Q. Then we have here a direct relationship between pressure decline and loss of gas in place, don't we?
A. Yes.

* * * * *

By Mr. March:

Q. Well, take his original recoverable reserves. What is your figure there at 25 pounds before you apply your recovery factor?
A. Well, they aren't recoverable reserves.
Q. Well, original recoverable, it says.
A. Well, that column you are refering to I believe says "Product," doesn't it?
Q. Well, I was referring to—yes. We'll say "Product" there. I was referring to the other column but I see I should have been referring to this one. What does "Product" mean?
A. I first found the amount of gas in place at zero pounds absolute.
Q. Originally?
A. Yes. Then in order to reduce that to wellhead gauge

pressures it is necessary to apply a Bureau of Mines' formula reducing it from zero absolute pressure in the field to the zero gauge pressure or 25 pounds gauge pressure or any other desired gauge pressure and so I multiplied the original reserve in place at zero absolute by this Bureau of Mines factor, getting a product which shows in Column 4 on Table A.

Q. Yes. It's 18,542,518,240,000.

A. At 25 pounds.

Q. Yes.

A. 18,542,518,240,000 cubic feet.

Q. Now, just above there is another figure which represents, as I see it, the product at zero gauge.

A. At zero gauge, that's right.

Q. What is that?

A. 19,661,265,912,000 cubic feet.

Q. All right, assuming that you would abandon at 25 pounds, you wouldn't produce any more gas, then between 25 pounds and zero is over a trillion cubic feet of gas, isn't there?

A. Yes.

Q. Now, does that amount to 10 per cent of the gas—does that amount to 10 per cent of the product at 25 pounds abandonment pressure?

A. No, it would amount to approximately six per cent, I believe.

Q. Six per cent?

A. Approximately that.

Q. Well, have you computed it?

A. No, I haven't, but 1 trillion is one-eighteenth of 18 trillion and I just made a rough guess. If it were 20 trillion it would be 5 per cent.

Q. Yes. In other words, the amount of gas which would be between zero pounds and 25 pounds at 25 pounds gauge would be approximately 6 per cent of your 18 trillion, which is the figure you have at 25 pounds, is that correct?

A. Yes.

Q. All right, now, there you have 6 per cent that you are going to assume that is in the formations, that you are not going to get out, that you are not going to want to get out.

Now, I ask you, when you pulled down to 25 pounds and still have 6 per cent of your total reserve—that's correct, isn't it—total original reserves?

A. Yes.

Q. —still in place, doesn't that make due allowance for any gas that would be impossible to recover?

A. No, I think you are confused, Mr. March. Now, that figure there we have been discussing—18 trillions plus represents just a mathematical calculation of the total gas existing in the field. I mean the total gas which could be withdrawn from the field, assuming that the field has an equal pressure of 25 pounds all over the field, not only at the wellhead but back away from the wellhead where we know there would be substantially higher pressures. Now, the gas represented by those substantially higher pressures would not be recovered, so it must be deducted from this total to get a recoverable figure.

Q. Yes, but you have 6 per cent there that you are saying that you will never recover, assuming every well goes down to 25 pounds before it is abandoned.

A. Well, that abandonment pressure may be arbitrarily selected at any point.

Q. Well, if we went up higher you would have a larger percentage in place between your zero and 25 pounds.

A. Sure.

The Trial Examiner: Mr. March, aren't you talking about the pressure for the entire field being down to 25 pounds rather than a 25-pound wellhead abandonment pressure?

Mr. March: I am talking about the wellhead abandonment pressure here at 25 pounds. I am saying this, Mr. Examiner: Assuming that every well did go down to 25-pound abandonment pressure, admitting that there would be pressures higher than that out in the formations and still gas left in the formations, that when you have a difference—by abandoning at 25 pounds you leave in the field at least 6 per cent of your reserves and that takes care of the situation instead of having to go ahead and apply another factor to the thing.

Mr. Spencer: Mr. Examiner, I think he has answered himself. Whenever he reduces his reserves to 6 per cent, then he must have less than 25 pounds at the wellhead.

Mr. March: I am not going to reduce them. That's just the point. I am glad you brought that up. I am not going to reduce them to zero. I am going to leave them at 25 pounds and abandon them there, and that leaves 6 per cent of my reserves in the field. Now, I want to know why it is necessary to go ahead and apply another 10 per cent there and leave 16 per cent of the reserves in the field.

The Witness: Well, this basic calculation—I'll read the figures: The original reserve in place at zero absolute is indicated as being slightly over 20 trillion; then we make a basic calculation which assumes that you are going to get every foot of gas in the Panhandle field down to 25 pounds abandonment pressure. You multiply that 20 trillion plus by .91507 and arrive at 18,542,000,000,000, and so forth, which is absolutely all the gas there is in the field above 25 pounds abandonment pressure. You are assuming that you are going to get every foot of it.

Now, you won't get every foot of it because we know that there will be pressures in the field that will be substantially higher. Therefore, I feel that it is necessary to add a recovery factor.

By Mr. March:

Q. Yes, but if we abandon down to 25 pounds, leaving 6 per cent of the gas in the field, doesn't that take care of the gas which you couldn't get out if you went down to zero? In other words, here the situation is, Mr. Thompson, as I see it, if you abandon at 25 pounds instead of going back to zero, why, that leaves 6 per cent of the gas in place in the field.

Mr. Spencer: It leaves more than that. That's what he has been testifying.

The Witness: 6 per cent plus.

By Mr. March:

Q. 6 per cent in place in the field?

A. 6 per cent plus—

Q. Just a moment. But if you went down to zero, then you wouldn't have 6 per cent. You could then apply a recovery factor of 10 per cent because you wouldn't have

abandoned above zero, therefore, you couldn't have taken care of any of your gas which you could not recover which was out in the formations.

A. I think I have made my position just as clear as I can make it, Mr. March, on that.

Q. All right, sir. Now, I note with a great deal of interest the statement that Cotner and Crum made. I want to read it to you and see what you think about it.

Mr. Lange: What's the page number?

Mr. March: Page 895, the last paragraph on Page 895.

"As no water is present on structure in the gas pays or directly under them, the Panhandle field will no doubt have an ultimate recovery of all gas in the reservoir with the exception of a very small percentage." Do you agree with that statement?

A. Yes.

Q. All right, sir, that's all I wanted to know.

A. 10 per cent is a very small percentage.

Q. How's that?

A. 10 per cent is a very small percentage.

Q. Yes, but at 25 pounds you wouldn't have 10 per cent in the formations, you would have 16 per cent in the formations, is that correct?

A. Approximately.

Q. Yes, so, therefore, although 10 per cent is a very small amount, when you get up to 16 per cent, that's going up the line, isn't it?

Mr. Spencer: It is more.

The Witness: Yes, but I can tell you just exactly what Cotner meant by that.

Mr. March: I don't want you to tell me what he meant, because I don't think that anybody can tell what any other man means and give an intelligent construction of it.

The Witness: I would like to do that if I may.

Mr. March: I want to subpoena Mr. Cotner in here if there is going to be that kind of testimony permitted.

Witness Thompson also testified (Vol. 76, pp. 11134-11139; 11171-11173; 11242-11245) as follows:

Q. Now, I note that on Mr. Peterson's map he has a heavy line separating the two parts of the field, the east field from the west field. Is there drainage today—movement of gas between the east field and the west field, in your opinion?

A. I would say that there is no effective drainage—no pronounced drainage at this time in either direction.

Q. Would you say that there was slight?

A. Oh, there might be a slight drainage.

Q. Which way is the slight drainage?

A. Both ways—from the area shown colored yellow immediately south of the block fault area indicated in central Gray County. You will note that the contour of the isobars would indicate a drainage from that yellow area northeastward towards Wheeler County and also northwestward toward northwest Gray County.

Q. Do you know what extent that yellow area has changed during the last five years—the pressures there—looking at Exhibit 187?

A. Well, it couldn't have changed much. It is still about 400 pounds.

Q. If there is still about 400 pounds, then there could be little or no drainage, could there?

A. I said it was slight drainage.

Mr. Keffer: May I ask a question there?

Mr. March: Yes.

Mr. Keffer: Did you say, Mr. Thompson—or, would you say, Mr. Thompson, that five years ago that the whole area south of the barren spot in Gray County might not have been 400 pounds? In other words, your yellow area now above 400 pounds may be smaller today than it was five years ago, for example?

The Witness: Well, I am sure that it is smaller than it was five years ago.

By Mr. March:

Q. Now, Mr. Thompson, since there is no effective movement of gas from the east field to the west field and from the west field to the east field, just why in the world do you include the whole field in your estimate of reserves?

A. Well—

Mr. Keffer: I might make just one correction on the question you asked. You said "effective drainage" and I think Mr. Thompson said "pronounced drainage." That may be a distinction without much difference, but there is that difference.

By Mr. March:

Q. Well, is there any effective drainage between those two fields, the east field and the west field?

A. I don't consider that there is at this time. A situation might develop, however, that would make such drainage possible, and since the east field is losing its pressures rather rapidly, I can see the time coming when the pipe lines that are getting their gas from Wheeler County might build an extension over into the west field.

Q. If it moved over to the west field it would kind of equalize the situation, wouldn't it, and prevent any drainage to the east field?

A. Well, it would just add to the gas withdrawals from the west field. Naturally, it would tend to equalize them, having exhausted the gas in the east field, and they moved over to the west, why, that would just tend to exhaust the west field.

Q. Wouldn't gas move very very slowly through this low permeable formation south of the block?

A. Not in my opinion. I think you are right as can be on that.

Q. As I see, to the north here you have, for example, around the Lefors area, you have a very low pressure area which remains low in spite of the fact that there is large pressures around there. Now, if that hasn't built up, why, it is not likely that there will be any drainage from the east field to the west field or vice versa until those pressures build back up, is there?

A. No. Both the west field and the east field are now contributing to the repressuring of this oil producing area shown colored gray in the area immediately north of the block fault in Gray County.

Q. Well, this low area around Lefors here?

A. Yes.

Q. Are the pressures increasing?

A. I haven't made a study of that and I don't know, Mr. March.

Q. I see your isobar map indicates, I believe, here from 200 pounds in that area, about the lowest pressure in the field.

A. Yes, and that area in Wheeler County and in the Borger Sanford area in Hutchinson County are the largest low pressure areas in the field.

Q. If there wasn't any gas wells in the western part of the field, how long do you think it would take the gas wells in the eastern part of the field to drain the gas in the western part of the field, assuming you had the same formations you have got there now—the same structures, the same drilling program in this intervening area— the central area?

A. You mean if there were no oil and gas wells?

Q. No oil and gas wells, we'll say, west of the Roberts and Gray County lines.

A. West of the west lines of Roberts and Gray County?

Q. Yes, and you had the same structure which separates the two fields and you have the same productivity over on the eastern part of the field.

A. The same development conditions as now exists?

Q. Yes.

A. Oh, it would take a long time for the east field to have much effect on the west gas field.

Q. Two or three hundred years?

A. Oh, I don't know. I wouldn't even attempt to measure it in terms of years.

Q. It would be a very long time?

A. Yes, it would be a long time.

* * * * *

Does virgin pressures still exist in the Panhandle field of Texas?

A. I am not sure whether there is any place in the field where you have got absolutely virgin pressure, but there are areas where it is almost virgin pressure.

Q. All right. Now, as I see here, this helium dome is just about a little less than the difference between the nearest well in the Hugoton field and the nearest well in the Panhandle field on the north, is that correct?

A. The Hugoton field is up in Kansas.

Q. Yes.

A. That would be 50 or 60 miles away.

Q. The nearest well between the Hugoton field and the

Panhandle field, the nearest two wells aren't that far away, are they?

A. You didn't ask me that. You said the helium field.

Q. Well, I'll ask you that now.

A. There are wells in the Oklahoma Panhandle that are closer to the Amarillo field—I mean to the Panhandle field.

Q. About what is the distance between the nearest wells between the two fields, approximately?

A. Well, those wells in the Oklahoma Panhandle would be approximately—possibly 30 miles.

Q. The nearest one is 30 miles?

A. Yes.

Q. How do you know this is not all one great field, the Hugoton field and the Panhandle field of Texas?

A. I think they are separated by a syncline in northern Moore County. There may be a very small neck in northeastern Moore County which wouldn't be over three or four miles wide, where there may be a connection.

Now, that has not been proven and I wouldn't be willing to say that that connection exists, but I think there is a possibility that it may exist.

Q. The producing formations in the Hugoton field are just about the same as the Panhandle field.

A. That is my interpretation of it.

Q. There is an enormous amount of gas in the Hugoton field, isn't there?

A. I think there is. I am not in a position to discuss the Hugoton field as an expert because I have never made a close study of it.

Q. Has there been very much drilling between the two fields?

A. There have been several test wells drilled.

Q. There has been very little drilling, then, between the two fields?

A. That is right.

Q. It is largely unexplored in that area?

A. I think that is correct.

* * * * *

Q. Now, if there is a drainage indicated by your map—if there is drainage indicated by your map—I'm not saying that there is—isn't the principal cause of that drainage those Canadian River wells which are highly productive in the

southwestern part of Hutchinson County and the southeastern part of Moore County—northwestern part of Potter County—northeastern part of Potter County?

A. That appears to be true to me.

Q. Don't you think Canadian River is getting its share of the gas in there with all of those highly productive wells?

A. They are getting some of it as it goes by.

Q. As it goes by? How fast does it go by?

A. Well, I have seen those pressure contours change from year to year as we have drawn up the pressure contour maps of the field. There is always a very noticeable change with encroachment of the low pressure areas southwestward into Moore and Potter Counties.

Q. Do you know what the production of the Canadian River wells has been in the southwestern portion of Hutchinson County?

Mr. Spencer: Total or current?

Mr. March: Total from the beginning.

The Witness: I don't have that figure.

By Mr. March:

Q. Do you know what the total production of gas in the entire Hutchinson County area has been?

A. I don't have that figure.

Q. How do you know any gas is getting by?

A. By changes from year to year in pressure contour maps.

Q. Well, with all the enormous production which the Canadian River takes out of that area, aren't they largely responsible for bringing those pressures down there themselves?

A. They contribute to the falling pressure, but I don't think they are solely responsible.

Q. If they were producing their 25 per cent there they would certainly be contributing considerably to the decrease in pressures, would they not?

Mr. Spencer: That is a hypothetical question.

Mr. March: I am asking it that way.

The Witness: If they are producing 25 per cent of their capacity?

By Mr. March:

Q. That is right.

A. They would be contributing very substantially to the fall in rock pressure.

Q. Have you made any study to ascertain just what percentage of the total decline in rock pressure they are responsible for in that area?

A. I have made such a study but I am unable to give what the results were now. I don't remember.

Q. You really can't say, can you, for certain, if any gas is going to the lower pressure areas in the northeast?

A. I think that is unquestionable.

Q. Have you any figure to sustain that?

A. No. I can give you one illustration that I think might be valuable. In the Sanford-Borger area in spite of the fact that substantial production of gas is being taken, the rock pressures of the wells that are actually producing are rising from year to year.

Q. How much are they rising?

A. It varies quite a lot.

Q. What are the pressures in there now? It seems to me they are pretty low.

A. This booklet I have here in my hand is a booklet put out by the Dwight Well Log Service showing the determinations from tests completed by the Railroad Commission of the State of Texas for the summer of 1940. I have gone through reports of previous years and marked down the lowest rock pressures of any given well in that area and the date when that lowest rock pressure occurred, and if you compare that lowest rock pressure with the present rock pressure, it is quite apparent that these wells are building up rather substantially.

J. D. Thompson, Jr., also testified with respect to testimony given some years ago in the United States District Court for the Northern District of Illinois, in the Chicago District Pipe Line Company case. Commission Counsel quoted from his testimony (Vol. 94, p. 14350) as follows:

"Q. In the figures that you have used with respect to the amount of gas originally in the field, did that or did it not refer to recoverable gas?

"A. It does cover recoverable gas.

"Q. Does it exclude gas which you do not consider re-

coverable which may be in the field? Perhaps I ought to ask you, will you explain what you mean by recoverable gas?

"The Master: Yes, I think that is proper.

"The Witness: Well, I have assumed practically 100 per cent recovery. That has been accomplished in other fields. As the gas becomes more valuable it is sometimes desirable to put gas wells on a suction or vacuum to get it all out finally.

J. D. Thompson, Jr., further testified with respect to the testimony given in the Chicago case, and above quoted (Vol. 94, pp. 14377-14380) as follows:

Q. Mr. Thompson, I almost overlooked the matter in which Mr. March interrogated you about with respect to your testimony in the Chicago District Pipe Line Company case which was held before a Master, I believe, in the Federal District Court in Chicago.

Mr. March: That's right.

By Mr. Keffer:

Q. You gave an estimate of the gas in the field as you stated this morning and also an estimate as to the life of the field and I believe that the portion you read, Mr. March, he also gave an estimate of withdrawals for 1935, 1936 and 1934, is that correct?

Mr. March: I think he has read that part.

Mr. Keffer: It is in the transcript. I just didn't want to go over that.

Mr. March: That was in there.

By Mr. Keffer:

Q. Now, that case was held—that hearing was held, as shown by this transcript, in the summer of 1934, was it not?
A. Yes.
Q. Will you state, Mr. Thompson, whether there were any unusual conditions or at least any conditions occurring in the field or present in the field at that time which are not present in the field today?

A. Yes, there were. They were stripping and blowing to air huge quantities of gas.

Q. I will ask you whether you recall that an increase of stripping operations and popping gas into the air—whether it was on the increase or decrease at that time.

A. At that time it was on the increase.

Q. Was there any indication that you know of at that time that that practice would be stopped?

A. No, I anticipated that it would continue.

Q. If that practice had continued on through the years, certainly there would have been a much larger production of gas from the Panhandle up to this time than has been the case, is that not true?

A. Yes, that's true.

Q. Now, you also stated at that hearing, as disclosed by the reading of the transcript this morning which covered a portion of your testimony, that all of the gas in the Panhandle down to zero pounds pressure would be recovered, is that correct?

A. Yes, I did.

Q. I will ask you if there were any circumstances or conditions existing in the field at that time which do not exist today that caused you to believe that gas would be produced down to zero pounds in the Panhandle gas field?

A. Yes, the stripping plants had no transportation problem at all. They merely took the gas from the well, stripped the gasoline out of it, and popped the residue into the air. They could withdraw gas down to zero pounds in my opinion.

Q. The gas which was supplied in a given stripping plant was generally collected right around close to the plant, was it not?

A. Yes, I believe that is true.

Q. Not only did they have no pressure problems as far as popping the gas into the air, but they had a very insignificant pressure problem with respect to gathering the gas, did they not?

A. That is right.

Q. Do you believe that pipe lines in the Panhandle gas field will withdraw gas down to zero pounds pressure?

A. No, I think that they will do.

* * * * *

J. D. Thompson, Jr., further testified (Vol. 94, pp. 14388-14391; 14405-14407) as follows:

Recross Examination.

By Mr. March:

Q. Now, Mr. Thompson, do you know those wells that you just recited off here in the center of Potter County in the yellow area, have declines in pressures from 1939 to 1940?

A. Yes.

Q. Have you made a study of production from those wells during that period?

A. Oh, to a certain extent I probably have but not for the purposes of submitting any testimony here.

Q. Well, now, Mr. Thompson, then you don't know whether or not they produced enough gas, then, to drain that area themselves, do you? Strike that.

Do you know whether or not the wells that you just recited here as losing pressure during that period, that this one well up here in Section 31 was losing pressure without any production—eight pounds in pressure—do you know whether or not those other wells were producing large quantities of gas?

A. I presume they were producing rather substantial amounts of gas.

Q. Have you got the production there?

A. No, I don't have the production here.

Q. You testified I believe previously that you had made no study of the production from these various pressure zones which you have here. Well, now, have you since my last examination of you made any examination of the production of those wells?

A. You are referring now to the wells in Potter County?

Q. That's right.

A. No, I haven't.

Q. Well, now, Mr. Thompson, if you have not, how can you state that the reason—or imply the reason that this one well lost pressure of eight pounds without any production was because of long distance drainage over towards the Sanford-Borger area?

A. I think you are misstating what I said a little bit.

Q. You don't mean to leave that impression?

A. I meant to say that it has lost in pressure, which was due to drainage mostly to the north and northwest. I think that is the most reasonable interpretation that you can make on it.

Q. And have you studied the production of the field during that same period immediately to the north and to the northeast?

Mr. Spencer: He says he has not, Mr. March.

The Witness: No, I haven't.

By Mr. March:

Q. All right, then, how do you know, Mr. Thompson, that that gas which moves away from this one well here in Section 37 was not because of local drainage to other Canadian River wells right in the area?

A. You say in Section 37?

Q. Section 31.

A. 31, yes. I don't know exactly to which well such drainage might have gone.

Q. As a matter of fact, Mr. Thompson, if you haven't made a detailed study of the production of the wells and the Canadian River wells surrounding this one well and the wells which you recited a few moments ago, you can't tell whether or not it was local drainage because of the movement of about eight pounds away from that well or not or whether or not it was long distance drainage, can you?

A. I don't believe I claimed that that eight pounds moved a long distance. I am sure I didn't.

Q. Well, now, if these other wells that you recited here did have very substantial production during 1939 to 1940, it is very likely that they could themselves have been responsible for pulling that eight pounds down—the pressure down eight pounds.

A. Partially responsible but not competely responsible.

Q. What makes you think it is not completely responsible?

A. Because I think you have got a general migration of gas to the north and northeast all through that country.

Q. To the north is a chain of Canadian River wells, isn't there?

A. Yes.

Q. Then you haven't made a study of the production of those Canadian River wells to find out whether they could not have taken that gas, have you?

A. No. I have answered that question about ten times that I haven't.

* * * * *

Q. You were going to find out for me, Mr. Thompson, how many wells were producing gas in Hutchinson county. Did you obtain that information?

A. I believe so. The Railroad Commission listed in 1940 a total of 303 gas wells in Hutchinson County and also 14 oil wells which were producing some gas.

Q. How many wells—strike that. How many wells in the Borger-Sanford area have been sour gas wells that have blown sweet gas, do you know?

A. What do you mean? What do you mean "have blown sweet"?

Q. That is right. How many of the sour gas wells have turned sweet?

A. I have no data on that with me here at all.

Q. Did you ever make a study of it?

A. I have made observations concerning it on several occasions.

Q. If there has been vast amounts of gas removed from Moore County and Potter County and Carson County, sweet gas areas over into the Borger-Sanford area, why isn't all of that area sweet gas now?

A. Because there hasn't been enough gas to go over there yet to change it from sour gas to sweet gas.

Mr. March: That is all.

Redirect Examination.

By Mr. Keffer:

Q. Mr. Thompson, in respect to the last question that was just asked you—I am stating the law in this respect—it takes very little hydrogen sulphide to make gas sour, does it not?

Mr. Lange: Of course the law provides for the content.

Mr. Keffer: That is right. Mr. Thompson may not know the exact content but he knows it takes very little hydrogen sulphide to classify the gas as sour.

Q. Is that right, Mr. Thompson?

A. Yes, I do know that.

Q. And the wells in the Borger-Sanford area originally had a very high content of hydrogen sulphide, didn't they?

A. That is my information.

Q. Take an area in which the pressures have gone down to 200 pounds. There would still be a lot of gas left, wouldn't there?

A. Yes.

Q. Then as sweet gas migrated into the area where there was gas of hydrogen sulphide content to mix with it, it would take a tremendous volume of sweet gas to bring the hydrogen sulphide content down to the point where it would be classified as sweet gas, wouldn't it?

A. Yes.

Testimony of C. Dox Hughes
Witness for Canadian.

Canadian offered C. Dox Hughes as a witness, who submitted a reserve estimate for the Texas Panhandle Gas Field. Mr. Hughes' testimony, with respect to his estimate, is as follows:

Qualifications

Witness was born in 1896 and is now a resident of Amarillo, Texas, having lived there since February, 1926.

His technical education was received at the University of Kansas where he completed his course in geology in June, 1920.

He accepted a position with Empire Gas and Fuel Company in the summer of 1920 at El Dorado, Kansas, where he was in charge of the Empire geological work in the Greenwood County area. This work included supervision of the drilling of wells and recommendations concerning acquisition or surrender of leases.

In 1922 he was transferred to Duncan, Oklahoma, and was made District Geologist for Southwest Oklahoma. His duties consisted of the supervision of the drilling of wells, recommendations as to lease purchases or surrender, and reconnaissance field work, and in this connection he studied the entire Permian and associated formations of western, south-

western and southern Oklahoma. Much of this reconnaissance work was done in connection with Dr. Chas. N. Gould. The witness subdivided and mapped a large area between the Wichita and Arbuckle mountains and interpreted the regional structural geology of that area. He directed considerable core drilling along the north side of the Wichita mountains and made discoveries which necessitated a complete reclassification of the Permian beds in southwestern Oklahoma. This work was of particular value with respect to the Texas Panhandle Field because of the similarity of the Wichita mountains to the sub surface conditions in the Texas Panhandle Field.

In December, 1925, he was given an assignment at Cisco, Texas, in charge of geological work for the Empire Gas and Fuel Company in that area.

In February, 1926, he was transferred to Amarillo, Texas, as District Geologist for the Empire in charge of the Texas Panhandle Field. Development in the Texas Panhandle Field was just getting under way at that time and the Empire was active in drilling wells in that area.

He resigned his position with the Empire in March, 1929, and has been an independent consulting geologist since that date with continuous residence in Amarillo, Texas. The bulk of his time has been spent on work in the Texas Panhandle Field but has also included studies of parts of New Mexico, Colorado, Kansas, Oklahoma, Louisiana, Arkansas, Missouri, Mississippi and Tennessee.

During the past several years the major portion of his work has been confined to the Texas Panhandle Field. His clients have included many of the large companies and individuals, land owners and royalty owners, gas companies, carbon black companies, gasoline plant operators and the Attorney General's office of Texas.

He has directed the purchase of considerable gas acreage based on his geological interpretations, which includes most of the acreage purchases by the Panhandle Eastern Pipe Line Company in the Texas Panhandle Field. He also supervised the drilling of most of the early wells for this company. He has purchased leases for Consolidated Gas

Utilities Corporation in Wheeler County. He has done consulting work on oil problems in this area, which included recommendations as to buying and selling of leases, royalties and wells, and also included appraisals for inheritance and income tax purposes.

During his services with the Empire Gas and Fuel Company he supervised the drilling of many oil and gas wells and observed the completion of many wells belonging to other companies and individuals. He did much work of this character also for the Panhandle Eastern and in addition to the wells with which he has had personal contact, he has kept abreast of the completions of wells since that time by means of logs, samples of formations and other records.

He recommended the purchase of a gas lease on some 60,000 acres of the Burnett ranch in Carson County, Texas, utilized by the Cities Service for a gas reserve for its Kansas City line, which was one of the first major trunk pipe lines out of the Texas Panhandle Field.

(Exhibit 211, pp. 1-7, Vol. LXIX, pp. 10043-49.)

Estimate of Gas Reserves

The methods employed by Hughes in estimating gas reserves in Texas Panhandle Field are generally described in Volume LXIX, pp. 10050-10064, and Exhibit 211, pp. 1-16.

Practically all gas wells in the Texas Panhandle Field are drilled (completed) with cabled tools. When gas is encountered it can be detected at the mouth of the well and as the drilling continues and the flow increases this can also be detected. If the producing formations were thick and soft and porous large volumes of gas would be blowing into the air, but on the other hand if the producing formations were thin and hard and tight the increase as drilling continued would be slight and upon the completion of the well a small amount of gas would be evident. After watching the completion of many of these wells the witness concluded that large wells were encountered where the combined effective producing formations were thick and soft and porous, or where there was some combination of this arrangement, and ordinarily small wells were encountered where the combined effective producing formations were thin and hard and tight, or where there was some combination of this arrangement.

There are some exceptions to this rule. A few gas wells in the field have encountered crevices or cavernous conditions where large volumes of gas were found upon merely reaching the pay formations. This is also true in some of the Granite Wash wells where the vertical permeability is extremely well developed and where large volumes of gas are obtained immediately upon encountering the pay formations. These wells are in the minority. Based upon his own observations affecting several hundred wells, the witness has concluded that large gas wells occur where the pay is thick and soft and porous and that small wells occur where the pay is thin and hard and tight. The witness stated that this was also the unanimous opinion of others who are familiar with the Texas Panhandle Field.

The original virgin reservoir pressure was the same over the entire field. Reserves of gas in place is dependent upon pressure and upon the effective pay thickness and its porosity. Although there are slight variations it can be stated that the open flow volume of a well is dependent upon thickness of pay and permeability of the pay. Vertical permeability in this field is usually low which makes it necessary, generally speaking, to penetrate the entire producing formation. Since the large open flow wells are found where the producing formations are soft and porous it follows that in the Texas Panhandle Field permeability is best where the porosity is best and permeability is least where the porosity is the least. It is the witness' opinion, therefore, that for practical purposes permeability varies with porosity.

Virgin Natural Open Flow is an important index to Original-Gas Content because:

Reserves are governed by

Pressure (this is the same factor affecting both Reserve and Open Flows).

Thickness (this is the same factor affecting both Reserve and Open Flows).

Porosity (for practical purposes, in the Texas Panhandle this varies with Permeability).

Open Flows are governed by

Pressure (this is the same factor affecting both Open Flows and Reserve).

Thickness (this is the same factor affecting both Open Flows and Reserve).

Permeability (for practical purposes, in the Texas Panhandle this varies with Porosity).

The witness stated that if small gas wells were discovered in the Texas Panhandle Field where the pay was soft and porous, but low in permeability, then his conclusions would not be true. He stated, however, that the small wells did not occur under these conditions but on the contrary they do occur where the pay (producing formation) is hard and tight. There are exceptions to this general rule which consists of the freak wells which encounter their entire open flow volume upon reaching the pay. These wells are usually within areas of more normal conditions as indicated by normal wells around them and can thus be appraised as freaks (exceptions), but even if treated at full value in accordance with the open flows they would not affect the answer on the whole to any very great extent since the areas they affect are small.

There is a direct relation in the Texas Panhandle Field between virgin natural open flow and original gas reserves in place. The witness made some computations in 1930 based upon the porosity-thickness method and which computations included a number of gas wells upon which he had the most reliable information. These calculations indicated that where his thickness and porosity computations indicated a reserve of 10,000,000 cubic feet per acre that the well itself had about 10,000,000 cubic feet open flow and where the thickness and porosity calculation indicated 5,000,000 cubic feet per acre the well itself had about 5,000,000 cubic feet open flow. He then concluded that it was practical to go from the known areas into the unknown by means of the open flow comparisons without making thickness and porosity determinations. The virgin natural open flow in the unknown areas served as indicators of reserve, or original gas content in place. It then became his practice to arrive at estimates of

the gas content of leases by comparing the open flows of the wells in the areas in question with those areas concerning which he had complete data.

He has used this method for the past 10 years in his consulting work for various companies, large and small, independent operators, lease buyers and sellers, royalty buyers and sellers, individual land owners and royalty owners. This method has been used in making appraisals for concerns proposing to drill wells and build pipe lines and proposing the purchase of leases and wells and royalties as well as for the selling of leases and wells and royalties, and in connection with carbon black plant operations and proposed pipe line expansions and for inheritance and income tax settlements.

In the early stages of the development of this method his studies were on portions of the field only and involved separate leases and tracts and did not involve the entire field. When he later made estimates of the reserves for the entire field the method was then applied to the field as a whole. The application was made to the field as a whole by means of a map of the field which showed the natural open flow or potential of each well under virgin or approximately virgin rock pressure conditions. The field was divided into classifications based on open flows, but in determining his classifications he used in addition to the open flows his knowledge of structural and stratigraphic geology at the well and in the various areas of the field. In some cases the boundary lines between zones or classifications of acreage took into account corrections for wells that had been drilled in at slightly reduced pressures which meant that the well would have been larger had it come in at virgin pressure. The witness has later taken this into account by actually correcting the open flows of the wells to virgin pressure conditions before placing the open flow on the map. Such corrections have been made in accordance with the United States Bureau of Mines back-pressure curves. The witness then determined the average potential or open flow for each zone shown on his map. This was done by averaging the open flows of all of the wells in each zone after having studied the distribution of the wells and after having concluded that the average was representative. The witness

stated that there would be minor variations with respect to the exact limits of each zone but that this was taken into account in arriving at his average figure as representing the open flow of each of his zones.

These zones are shown in the colors on the zone map or productivity map prepared by Hughes, Exhibit 212.

The method has been refined from time to time, the greatest refinement having come with the completion of new wells giving more complete information on the exact zoning of the field by potentials or open flows. The field has been enlarged somewhat by the acceptance of the Railroad Commission's outline of the field. This has resulted in the inclusion of some 200,000 acres which the witness considered practically worthless for gas production. This also resulted in the addition of an additional zone to the potential or productivity map (Exhibit 212) so that now the witness uses five zones, the lowest zone being from zero to 500,000 cubic feet potential.

Additional refinements have come through the application of Boyle's Law (pressure decline) at various times and in various ways. This was accomplished by applying Boyle's Law at different times to areas within the field where it was considered that the effect of drainage could be evaluated and by weighting the pressures with acreage times potential instead of weighting pressures with acreage only. This gave a better weighted pressure because potential along with acreage constituted a better index to the varying volumes of gas contained in the formations. The application of Boyle's Law (pressure decline) to various parts of the field constituted a check or test on the witness' original observations but did not result in a revision of the factor of .919211, which is the factor he is now using and has used for a number of years. The areas utilized in testing the method are located in the eastern part of the field, the central portion of the field and the western portion of the field are representative of the field as a whole.

The estimate of original gas reserves of the field by the utilization of this method and by the application of the .919211 factor to the average potentials or open flows is described briefly as follows:

The average in each zone shown on the productivity map (Exhibit 212) is determined by actual measurement from the map.

The average open flow for the wells in each zone is also determined, corrections being made as hereinafter shown where such corrections are necessary. Consideration is also given to structural conditions and other data in order to arrive at a true virgin open flow condition or relationship.

The average potential or open flow for each zone, determined as hereinabove outlined, is then multiplied by the acreage in each zone. There is then applied to this product the factor of .919211. In other words the witness takes approximately 92 per cent of the product of acreage times average potential or open flow, which results in the volume of gas at zero pounds bottom hole or absolute pressure on a 16.4 pound pressure base. The sum of these products is then added, which gives the volume of gas in place for the entire field.

The addition of these sums for each zone results in a grand total of 19,822,646,947 Mcf. as the original reserve or gas content at zero pounds bottom hole on a 16.4 pound pressure base and this figure converted to a zero pounds wellhead pressure gives 19,233,517,929 Mcf. as the original volume of gas in place at zero pounds wellhead pressure.

The witness has then applied to this figure a recovery factor of 90 per cent. (The reasons for applying a 90 per cent recovery factor are hereinafter set out.) The result of the above computations gives an estimate of recoverable gas originally in place in the formation at zero pounds wellhead of 17,310,166,137 Mcf.

The witness has tabulated his estimate on page 15, Exhibit 211, giving his estimate of original recoverable gas in place at various assumed abandonment pressures from zero pounds wellhead to 100 pounds wellhead and also shows the present recoverable reserves as of August 1, 1939.

The estimates are as follows:

"Original Recoverable Gas Reserves of the Texas Panhandle Field on 16.4 Pounds Base, and 90% Recovery Factor:

0 lbs.	17,310,166,137 Mcf.
25 lbs.	16,325,198,631 Mcf.
50 lbs.	15,302,587,914 Mcf.
75 lbs.	14,279,798,799 Mcf.
100 lbs.	13,295,009,700 Mcf.

Total production from the field was 7,485,066,520 Mcf. at 8-1-39, and subtracting this from each of the above figures the

Present Recoverable Reserves
(at 8-1-39) follows:

0 lbs.	9,825,099,617 Mcf.
25 lbs.	8,840,132,111 Mcf.
50 lbs.	7,817,521,394 Mcf.
75 lbs.	6,794,732,279 Mcf.
100 lbs.	5,809,943,180 Mcf.

The above figures may be converted to a 14.65 pound base by multiplying by 1.11945."

The above estimates are based primarily upon computations made from data shown on the productivity map prepared by Hughes (Exhibit 212). The outline of the open flow zones as shown on this map have been revised from time to time where the drilling of additional wells made it necessary. Revisions have not always been made, however, where the open flow of a well drilled in a particular zone did not correspond with the classification theretofore made. This is true particularly where the deviations from the zone map tended to compensate, and made no difference therefor, in the final result of the computations.

The witness in 1939 (Vol. LXXIX, pp. 11621-11624) again tested the zone classification (productivity classification) as shown on Exhibit 212, by studying the entire field in the light of all wells drilled in the field. He did this by classifying the entire field as to virgin natural open flow on a section by section basis (640 acres being a section) rather than by zones of similar open flow as shown on the map. Sections where no wells had been drilled were classified ac-

cording to the nearest development and according to geology as far as possible. The geology took into account structural position, type of pay (formation) to be expected, whether the tract was located in an area where the pay (formation) was well developed or not, and trends in those areas where evidence of porosity conditions existed. This proved to be a satisfactory confirmation of the zone or productivity map, Exhibt 212, although the computation based on the map gave a somewhat higher reserve estimate.

Hughes further testified on cross-examination that his method of estimating reserves, based upon potentials or open flow of wells, as corrected, is not a new method, but is one that has been in use in the oil business for a long time, and although the witness does not know of anyone that has used the method directly as he has used it, he has been convinced of its soundness for several years. (Vol. LXXVIII, pp. 11496, 11497.) That the only thing he had done in this case was to apply a well-known relationship between potentials of oil wells and reserves of oil. He has applied the same basic method to the gas field apd in his opinion it should work better in a gas field than it does in an oil field. (Vol. LXXVIII, p. 11525.) The method follows the fundamentals of physics. The pressure in the formation is one of the factors which you must know in order to estimate gas reserves. Thickness of the producing formations is another thing you must know. You must also know the porosity, and by that the witness made it clear that he meant *effective* porosity, that is, inter-connected porosity in the formation. Pressure influences open flows. Permeability, of course, governs open flows and this is related to porosity because you can't have permeabilty unless you have some effective porosity. The two start from a common point. If there were no porosity there would be no permeability, and thus they end with a common point. Permeability generally increases with porosity. All of these things follow the fundamental laws of physics and they are also correlated with the witness' practical experience in the Texas Panhandle Field. (Vol. LXXVIII, pp. 11499-11501.)

In the early stages of the development of his method, as applied to the Texas Panhandle Field, the witness had determined the porosity and thickness of the producing for-

mations in different areas of the field. His determinations as to porosity were not based upon cores but were made from porous pay formations that had blown out when the wells were being drilled, which portions the witness knew were coming from the pay formations because they contained gas. (Vol. LXXVIII, pp. 11465, 11466, 11468.) Pay thicknesses were determined from wells concerning which the witness had observed the actual drilling operations. (Vol. LXXVIII, p. 11471.) These observations in connection with the actual porosity and pay thickness determinations in these areas caused the witness to conclude that there was a relationship between potentials and reserves. (Vol. LXXVIII, pp. 11476, 11477, 11478.) The witness first determined the actual gas in place and relating this to the open flow volumes of the wells, arrived at a relationship. (Vol. LXXIX, p. 11610.) The initial tests were made prior to 1930 on a group of wells on the Burnett ranch in Carson County, Texas (Vol. LXXVIII, p. 11479); also tests in Wheeler County (Vol. LXXIX, p. 11679); also other studies and observations more recently in the western portion of the field (Vol. LXXIX, p. 11680), and his most recent study shows that his conversion factor should be lower than the one he has used in his Exhibit 211 (Vol. LXXIX, p. 11680).

The reasonableness of the factor has been further checked by taking each 640-acre tract in the field and making estimates as to each such tract which gave a figure a little less than his over-all estimate in this case. (Vol. LXXVIII, pp. 11548-11550, Vol. LXXIX, pp. 11623, 11624.)

On cross-examination Hughes was challenged by Commission counsel to cite any specific proof from published scientific journals to the effect that open flow indicated gas in place. The witness then referred to investigation 3313 of the United States Bureau of Mines, being a bulletin titled "Extent and Availabilty of Natural Gas Reserves in Michigan 'Stray' Sandstone, Horizon of Central Michigan." The report was prepared by E. L. Rawlins and M. A. Schellhardt. The report reflects that they made an estimate of gas reserves in Michigan on the porosity thickness method. To do this you must have porosity and you must also have thickness. The witness then quoted from the bulletin as follows:

"Two principal methods of analysis have been used in this report to determine the average productive thickness through a field. The first method is based on an average of the interpreted productive thickness of the individual wells in the field being studied."

"The second method is based upon an interpretation of average open flow volume per foot of productive thickness * * *."

The witness stated that it is quote obvious that Rawlins and Schellhardt arrived at thicknesses in individual wells that were studied, and in some wells where the thicknesses were unknown they used the open flow as an indicator of the thickness.

The witness stated that the persons making the estimate had to have an estimate of porosity and in order to relate this to an estimate of thickness of the sand, the open flow was taken as a guide. The witness doesn't assume an average porosity to relate to his open flow, and he stated that if he desired to follow specifically what was done in Central Michigan that he could assume a porosity of 20 per cent, say, and by means of the open flow estimate pay thickness. He could then use the porosity and thickness as the basis for a computation of reserves.

The only difference between what the witness does and what Rawlins and Schellhardt did was that the witness considered open flow as a guide to both porosity and thickness, while the others had an assumed porosity and with that assumed porosity considered the open flow as a definite guide to thickness. (Vol. LXXXV, pp. 12691-12694.)

The witness then stated that he had discussed with Rawlins just what he was doing in the Texas Panhandle Field, and how he had arrived at a relationship between open flows and reserves in place. He attempted to relate the conversation he had had with Rawlins on this subject. This was objected to by counsel for the Commission and the soundness of the objection was granted by counsel for Canadian and the conversation was not related. (Vol. LXXXV, pp. 12695, 12696.)

The witness stated that Rawlins and Schellhardt recog-

nized the direct relationship between open flow and reserves in place and merely went through the mathematics of showing the pay thickness that was necessary to accommodate that given relationship. It was an assumed proposition all the way through based upon the definite recognition of the relationship between open flow and the reserves in place. Vol. LXXXV, p. 12697.)

The witness again reiterated that what he did was to arrive at thicknesses and porosities in a group of wells, from which point with an observed relationship between open flow and reserves he went directly from that to the field as a whole and applied the relationship to the field as a whole. (Vol. LXXXV, p. 12698.)

The witness observed the thickness and porosity on a group of wells that established the relationship between open flows of those wells and the reserves, and Rawlins did the same thing in Michigan. (Vol. LXXXV, p. 12700.)

Productivity Map, Exhibit 212

Exhibit 212 shows a picture of the entire Texas Panhandle Field with respect to the various zones of productivity.

The legend on the map, Exhibit 212, indicates the zone of productivity evidenced by each color. The yellow color represents those portions of the field where the open flows of the wells are above 40,000,000 cubic feet per day. The area colored green represents the areas in which the open flows of the wells range from 25,000,000 to 40,000,000 cubic feet per day. The red color represents areas where the open flows of the wells range from 10,000,000 to 20,000,000 cubic feet per day. The blue color represents areas where the open flows of the wells range from 5,000,000 to 10,000,000 cubic feet per day. The gray color represents areas where the open flows range from zero to 5,000,000 cubic feet per day. (Vol. LXIX, pp. 10067-10071.)

Hughes stated on cross-examination that the zones of productivity shown on Exhibit 212 represent the appraisal of the witness with respect to the productivity of each zone (Vol. LXXVIII, p. 11527) and in the witness' opinion the zone map is sufficiently accurate to enable him to make his computations. (Vol. LXXVIII, p. 11528.)

The map classifies the entire field approximately in accordance with the open flows that would be expected to be found by wells drilled in the different zones had they been drilled at the time the field was all virgin pressure. The initial potentials utilized in constructing the map were gathered from various sources, including all of the logs the witness has accumulated over a period of years, investigations that he has made, and reports on various wells where he has had occasion to make a more detailed check, as well as a study of scout reports and tickets and many other types of information." (Vol. LXXIX, pp. 11618-11620.)

The drilling of subsequent wells, the open flows of which do not correspond precisely with the classifications on the map, does not destroy the value of the map for the reason that those deviations have actually averaged out—for example, the zone map that was made a year ahead of the present map and which was based upon the information that the witness had collected at that time, gave a total product of acres times potential approximately the same as the present map made a year later, after approximately 100 new wells had been drilled and spotted on the map. (LXXIX, pp. 11621-11624.)

Still a year later another survey of the field was made after an additional 100 wells, approximately, had been drilled and this study was based upon a section by section appraisal (640 acres to a section) of the potentials, and resulted in approximately the same figure. The drilling of new wells changed the picture so little that the witness did not change his estimate of reserves. (LXXIX, pp. 11621-11624.)

Some of the wells came in with a lower potential than the zone map would have indicated and others came in with a higher potential but the net result was that these deviations compensated each other. (Vol. LXXIX, pp. 11621-11624.) As a matter of fact the map is subject to being revised every time a new well comes in, but on the other hand, past experience has shown that these revisions when made have been so slight that the difference in the zones as figured over the entire field, is negligible. (Vol. LXXIX, p. 11669.)

The witness' attention was called to a number of possible

discrepancies, that is, concerning wells that were not shown in the proper productivity zones. The witness answered that such small discrepancies did not result in an erroneous zoning of the field; that in many instances he could have zoned certain areas or portions of areas lower than he did zone them, so that the errors, if they might be called such, are compensating ones (Vol. LXXIX, p. 11691), and that these small differences do not change the over-all picture. (Vol. LXXIX, p. 11677.) These possible discrepancies referred to are found generally in Vol. LXXIX at pages 11635 to 11731. The witness explained that the so-called discrepancies did not as a matter of fact exist but that the zoning of his map in the particulars referred to, was based upon his judgment of structural and geological conditions and his interpretation of the size and performance of other wells in the immediate area.

This was all checked very thoroughly by a section by section appraisal of the field, which check gave a somewhat lower figure than indicated by the map, Exhibit 212 (Vol. LXXIX, pp. 11694; 11695). Many of the wells shown on the map, Exhibit 212, were not converted back to virgin open flows, since this was done only as to wells completed in the past three years, but the great majority of wells, as shown on the map, were completed at dates when the pressures were still high and therefore represented approximate virgin conditions. There were also some wells drilled at lower pressures, as witness explained in his direct testimony, for which he made due allowances in the construction of his zone map. (Vol. LXXIX, pp. 11589, 11590, 11612-11614.)

The witness also stated that he had discounted to a certain extent the alleged well potentials in a portion of the sour gas area in north Moore County (Vol. LXXIX, p. 1185) and that this was necessary because sour gas is on a proration basis and that the potential of the well was a factor in determining its allowable production. That is, an operator could produce more gas legally from a high potential (open flow) well than from a well of lower potential and that he had discounted those wells for the reason that his investigation had convinced him that it was the sensible thing to do; that the high potentials in that area developed very largely after proration became effective and not before. (Vol. LXXIX, pp. 11859; 11860.)

A casual examination of the initial completions of wells in the Texas Panhandle Field shows that the exceptionally large wells were developed after operators of gasoline plants in that area became desirous of having as high a potential figure as they could get and by any means that they could get it. Some of the potential figures are taken with everything in perfect condition, every mechanical arrangement in perfect order. That has been the history of fields under proration. It is then that the demands arrive for high potentials in order to have a larger volume of production allocated to them. This is definitely the thing that has happened in the sour gas area of the Texas Panhandle Field. (Vol. LXXX, pp. 11836, 11837.) The extremely large wells generally are reported only in that part of the field where the operators need high potentials. They acidize them and shoot them and do everything else (to increase the potentials). (Vol. LXXX, p. 11838.)

The witness on redirect examination in support of the fact that he discounted to some degree the apparent open flows of the gas area of north Moore County, particularly, submitted a list of forty wells from that area. These forty wells were listed on the zone map, Exhibit 212, as having an average open flow of 50.7 million cubic feet per day. The witness then took the potentials of those same wells, as shown on the 1939 report of the Railroad Commission, and converted each one of them back to a 430-pound virgin open flow or potential. This calculation showed that the accurate original potential of those forty wells on the average, based upon their present performance, was only 31.64 million per day. In other words, the performance of those wells was only 60 per cent of what might have been expected from the open flows as originally reported and as shown on Hughes' zone map, Exhibit 212. (Vol. LXXXV, pp. 12723-12725.)

These wells are listed in Exhibit 212-A, which exhibit was marked for identification and introduced by Commission counsel. This exhibit shows the name and location of the wells, the original potential, as reported and as shown on Hughes' map, Exhibit 212, and the potentials as reported on the 1939 Railroad Commission report, but after the same had been converted back to the original potential at 430

pounds virgin rock pressure. The color band in which these wells were spotted on Hughes' zone or productivity map, Exhibit 212, and the color band on which these wells should have been spotted in view of the later performance of the same, is shown on the exhibit.

The witness again stated on redirect examination that although attorneys for the Commission had pointed out several cases where wells were placed in a lower zone of productivity than they should have been if potentials alone had been considered, that there were also many other instances where small wells, and even dry holes, had been placed in higher zone classifications than they should have been had potentials alone been considered, and that he had not seen fit to change his classifications simply because dry holes or small wells had been drilled in areas where large wells would have been expected; that although there are variations here and there from the zone or productivity map, Exhibit 212, it does nevertheless reflect rather accurately the productivity of the various areas in the field on an average. (Vol. LXXXV, pp. 12721, 12722, 12723.)

Later gauges by the Railroad Commission are very significant on wells of this type. Frequently the original reports did not represent gauges at all. This was all taken into account. (Vol. LXXIX, p. 11832.)

The witness further stated on cross-examination that he had not changed from his 1938 zone map as compared to his 1939 zone map, which is Exhibit 212. He had found from examination that he had enough wells in the different colored zones to show the proper average. This is especially true in the sour gas portion of the field because there the average figure was reached prior to the inauguration of proration in that area. Proration has caused a great demand for potential in that area and resulted in many cases in a definitely inflated figure. (Vol. LXXX, pp. 11835, 11836.)

Determination of Recovery Factor

Hughes' testimony with respect to the use of a recovery factor is set out in Volume LXIX, pages 10063 to 10066, Exhibit 211, pages 17 to 19.

It will be noted that on each computation of original gas in place at each assumed abandonment pressure that the

witness has determined the recoverable gas by taking 90 per cent of the estimated original reserves in place in each case. This has been done because the witness is of the opinion that the total original reserves of gas computed to any given abandonment pressure will not actually be produced.

When the average wellhead pressures in the field reach any particular abandonment pressure there will still exist pressure differentials out in the formation away from the well bore. The differentials must exist if the wells are to be produced down to the abandonment pressure. The differential consists of higher pressures, in the formation away from the well bore, than the pressures at the well. It necessarily results, therefore, that when the abandonment pressure is reached at the well that the average reservoir or formation pressure is some figure higher than that.

It is not possible to determine the exact volume of gas involved but it is definite that not as much gas will be produced down to an average well abandonment pressure as the computations to that point would indicate. It is apparent, therefore, that some percentage figure less than 100 indicates the recoverable gas.

Still another reason for using a recovery factor results from the effect of water that gets into the pay formation. Experience shows that water is actually getting into the reservoir from wells that have been drilled into bottom water and although these wells were plugged back they were not always successful in shutting off the water. It is known also that upper water is getting into the reservoir in some cases where casing has failed to completely shut off the water above the gas formations. This water from whatever source contaminates areas by horizontal migration after it gets into the formation. This results in the trapping off of gas in the formations thereby rendering it unrecoverable. This also results in the salting of the formations at the well which renders a well incapable of production. Some wells have been abandoned due to this occurrence. Many wells have been abandoned due to the fact that water has flooded out the gas.

Several wells have been abandoned due to caving shales, collapsed casing, or low potentials. Most of these wells were

abandoned while general pressures in the areas in which they were located were around 100 pounds or more. Each abandonment of this type, besides leaving the area involved with a possible water contamination, actually increases the areas between the remaining wells in which pressure differentials will exist.

Still another reason for applying a recovery factor is the fact that many portions of the field contain hard, tight, lean areas which may never be drilled, and therefore, their gas content, even though small, will not be recovered completely.

Considering the effects of all of the foregoing reasons the witness has concluded that a 90% recovery factor would be a fair and reasonable figure to use.

Permeability as Related to Porosity

Witness further testified on cross-examination that the application of his method of the estimation of reserves in Texas Panhandle Field did not depend upon an absolute and direct relationship between porosity and permeability. Relationship between open flow and reserves exists whether there is a direct relationship between permeability and porosity or not, but that for practical purposes in the Texas Panhandle Field porosity varies with permeability. (Vol. LXXVIII, pp. 11517, 11518.) The relationship between porosity and permeability is only one of the factors that is involved in the relationship between open flow and reserves. (Vol. LXXVIII, p. 11516.)

Porosity and permeability determinations made by Shell Petroleum Corporation, Exhibit 218, indicate quite a definite relationship between permeability and porosity. The witness stated that these tests reflected that where the porosity was zero to 5% with an average porosity of 3.2%, the average permeability was .14, but where the porosities ranged from 5% to 10%, with an average of 7.7%, that the average permeability was 4.4. Where the porosities ranged between 10% to 15%, with an average of 12.4% the permeability was 21.7. Where the porosities ranged between 15% to 20%, with an average of 16.6%, the permeability was 55.2. Where the porosities were above 20% with an average of 23.1%, the permeability was 468.2. These tests all showed a definite

increase in permeability with the increase in porosity. (Vol. LXXVIII, pp. 11509-11511.) Witness stated that there will be a whole range of porosities and permeabilities in each individual well. A large well must have a large porosity in connection with a large permeability, otherwise the large open flow would not be a sustained open flow. The sustained large open flow must have large volumes of gas in the formation to sustain it and those large volumes of gas must have large porosity in order to accommodate it. (Vol. LXXVIII, pp. 11513, 11514.)

Conclusions as to relationship between porosity and permeability should not be based on just a few comparisons or determinations but you must study enough of them to be able to get average results and see what the average relationship is. However, a study of the Shell tests shows a surprising degree of relationship. (Vol. LXXVIII, p. 11519.) Another reason why isolated examples cannot be taken is the fact that the permeability determinations as well as the porosity determinations are made from small portions of the actual core. In some cases the exact sample taken is no larger than a man's little finger and then again the permeability tests are made from one portion and the porosity tests from another. (Vol. LXXVIII, pp. 11519, 11520.)

Open flow is dependent upon sand thickness and permeability which is tied-in definitely with porosity (Vol. LXXIX, p. 11650), but the fact remains in the Texas Panhandle Field that where wells are drilled into thick porous pays that you do not have low permeability. Small wells are found where the pays are hard and thin and tight. (Vol. LXXIX, p. 11655.)

Witness was further cross-examined with respect to authorities and tests as to the relationship between permeability and porosity. This examination referred particularly to the statements made by Muskat in his work on "Flow of Homogeneous Fluids" and certain data contained in tests made by Pennsylvania State College.

Hughes stated that he agreed with the conclusions reached by both Muskat and the engineers who collected the data contained in the Pennsylvania State College Bulletin, which conclusions were that porosity and permeability did not

necessarily vary directly. He stated that he had always been of the opinion that the relationship between the two was not a direct one but that he recognized, as do the authorities above referred to, that there is a relationship and that in some cases permeability and porosity did vary in the same manner. The witness stated that in his estimate of reserves in the Texas Panhandle Field he had made no claim that porosity and permeability varied directly, but his experience in the Texas Panhandle Field had convinced him that the relationship there between porosity and permeability was a close one and that, therefore, there was a direct relationship between open flow and reserves. The witness also called attention to the fact that the authorities above referred to, were dealing with *absolute* porosity, but that permeability is dependent upon *effective* porosity and not absolute porosity. The porous spaces must be connected in order to permit the flow of fluids through a solid. The witness also stated that the relationship between permeability and porosity would be much closer in a gas field than in an oil field because gas would flow more readily through porous spaces than a viscous fluid like oil. (Vol. LXXV, pp. 12680-12691.)

Testimony of Stanley Gill, Witness for Canadian.

Qualifications

Witness was born in 1899 and resides in Houston, Texas, where he conducts a consulting engineering practice. He was educated as a mechanical engineer, graduating from the University of Washington in 1920 with the degree of B.S. in Chemical Engineering. After the completion of his undergraduate work he attended Columbia University for three years, completing the graduate course in engineering with the professional degree of Ch.E. early in 1923.

Following a year as Assistant in the Physics and Engineering Departments at Columbia University he was employed in February, 1924, as Industrial Fellow of the Mellon Institute of Industrial Research at Pittsburgh, Pennsylvania, and was assigned to the investigation of oil field and pipe line corrosion problems for the Gulf Production Company and the Gulf Pipe Line Company. He moved to Houston in February, 1924, and has remained there since that time.

From 1924 until the end of 1931, he was continuously engaged in engineering work for the Gulf Production Company. During this eight-year period his duties expanded from those of his original employment and during the latter part of such employment he had charge of a group of engineers engaged in research in all phases of production and pipe line operations.

In January, 1932, he opened a consulting engineering office in Houston and has carried on a consulting practice continuously since that time. His consulting work has been concerned with engineering applications in all branches of oil and gas production and transportation. Among the lines of work which have constituted the greater part of his engineering practice during recent years the following are cited:

(a) The design, construction, development and operation of instruments for geophysical exploration;

(b) Study and analysis of geological and geophysical data and recommendation as to drilling wells on the basis of such data;

(c) Assistance in and supervision of drilling operations, particularly as relating to high pressure technique and the control of mud-laden fluids;

(d) Design and testing of drilling and production equipment;

(e) Valuation of oil and gas properties, including estimation of reserves and of future earnings;

(f) Valuation of physical properties; and

(g) Design and operation of high pressure gasoline and condensate recovery and gas recycling plants.

Most of his clients are large independent oil producers, although he has done some work for major oil companies and for associated groups of royalty owners and small independent producers.

He has been familiar with the Texas Panhandle Field since 1926 or 1927. At that time his work in the field was in connection with special problems relating to oil production and transportation and particularly to corrosion of equipment.

His first detailed work in connection with gas production in the Texas Panhandle Field was in 1935, at which time he was employed as an expert witness in a case against the Railroad Commission. Since that time he has maintained close contact with developments in the Texas Panhandle Field. On a number of occasions he has been employed on matters relating to the field and he has also carried on independent studies of pressure and producing conditions in that area.

In addition to the experience which he has had in what might be considered the routine problems in the development and operation of oil and gas properties, it has been necessary in his consulting practice to devote a large portion of his time to the extraordinary problems which grow out of those operations on particular properties. This has necessitated extensive analytical studies with the aid of men of wide experience in, and practical knowledge of, the industry and the particular problem presented. An intelligent understanding of the various estimates of the gas reserves of the Texas Panhandle Field requires an analytical study of this character. (Vol. XCI, pp. 13973-13978, Exhibit 265, pp. 1-3.)

Witness further testified on cross-examination with respect to his qualifications that he was not a geologist although he had taken courses in geology in both the University of Washington and Columbia. (Vol. XCII, pp. 14062-14065.) The witness majored in chemical engineering at Columbia, which had little to do with petroleum. The witness explained, however, that he was one of the generation of chemical engineers who preceded formal education in petroleum engineering. Most of his generation of petroleum engineers were educated as chemical engineers, mining engineers, mechanical engineers, or something of that sort. Formal education in petroleum engineering emerged the latter part of the 1920's and is not yet standardized. (Vol. XCII, p. 14066.) The witness during his last year at Columbia had charge of four laboratories and quiz periods in the physics department. He handled the laboratories, conducted the regular quizzes and graded papers and later had charge of two of the large chemical engineering laboratories. He, in collaboration with an instructor, wrote a laboratory manual for the

course in advanced electro-chemistry. These were advanced courses. (Vol. XCII, p. 14068.)

Witness further stated that from the very beginning his problems were concerned with corrosion of oil well equipment and particularly with corrosion of oil well screens and wells in the Texas Gulf Coast. The solution of this problem is purely an economic one and relates to costs of recovery of oil. This being true, it became necessary in connection with the problem to make estimates of recoveries of oil, and therefore from the very start of his employment with Mellon Institute a very considerable part of his work would be classified as petroleum engineering, since it was concerned with questions of recovery. (Vol. XCII, pp. 14070, 14071.)

Counsel for the Commission then cross-examined the witness at length on his qualifications with respect to the estimation of oil and gas reserves. This cross-examination is found in Vol. XCII, on pages 14072 to 14129.) During the course of the examination the witness testified that he had made estimates of oil reserves in some 100 different fields and was cross-examined on some fifteen of them. He also stated that he had estimated gas reserves in some fifteen or twenty gas fields. He named fourteen of them and was cross-examined to some degree upon those named.

Determination of Effective Porosity, Texas Panhandle Field

Gill stated that the average porosity of 20%, assigned to the commercial acreage by Thompson, was the result of his many years experience in the Texas Panhandle Field and other gas fields. Peterson on the basis of a similar background of experience has arrived at the same conclusion as to average porosity. Thompson based his use of the 20 per cent porosity figure upon close observation of Texas Panhandle Field wells and upon correlation of the results of these observations with recoveries that had actually been had from other comparable areas.

Gill stated that the very few records of actual porosity determinations which have been made on cores of oil wells in the field indicate a considerably lower average porosity. This is usual in the case of limestone or dolomite pays from which it is seldom possible to obtain cores of the most

porous parts of the reservoir formation. In general, opinion as to over-all recovery anticipation affords a more reliable guide for reserve estimates than do the results of actual tests on cores. Even in sand reservoirs where good cores can be obtained, the core samples represent at best a microscopic sampling of the formation and are of value principally as a guide for judgment as to its character. In the most elaborate applications of core analyses for the estimation of oil reserves they apply judgment in the form of a recovery factor to arrive at final estimates that seem correct in the light of experience. In the case of limestone or dolomite reservoirs, judgment is of even greater importance.

The witness does not believe that he would himself apply an average porosity as high as 20 per cent to the limestone and dolomite pays of the Texas Panhandle Field. He has never made a careful study of the field from this point of view, but he has devoted a great deal of study to recoveries of oil out of the limestone reservoirs. Data on a group of such reservoirs are contained in Table I attached to Exhibit 265.

Table I contains a list of sixteen limestone producing fields in Texas and New Mexico showing the county in which such fields are located, the name of the field, the producing formation and the anticipated ultimate recovery of oil in barrels per acre foot.

Gill stated that anticipated recoveries out of all but two of these fields are very much less than would be expected out of formations of 20% average effective porosity. The two exceptions draw their production from highly fissured and cavernous cretaceous limestone, recovery from which is greatly facilitated by the presence of a very active water drive. With these exceptions, the oil reservoirs listed in Table I, Exhibit 265, will not yield ultimate recoveries corresponding to average effective porosities of more than 10% or 15%. It therefore appears to the witness that the 20% average effective porosity figure used by Thompson and Peterson may be too high. (Vol. XCI, pp. 14011-14013; Exhibit 265, pp. 29-30.)

The witness further testified on cross-examination that porosity determination could be made from well cuttings

and that this was done in the Turner Valley Field, for example, in Alberta Province, Canada, in which field witness had done considerable work and had estimated the gas reserves. The porosity determinations in that field were made from the well cuttings by the Canadian Government and Province of Alberta, and were utilized by witness in making an estimate of gas reserves in that field. It is impossible to make a good determination of effective porosity from such cuttings but you can make a good determination of total porosity which is higher than effective porosity. The cuttings which formed the basis for the total porosity determinations were made here from a limestone formation. The cuttings averaged a little over one quarter of an inch in length and possibly a little over an eighth of an inch in width, and possibly a twentieth of an inch in thickness, and were rotary cuttings. There were only two wells in the field in which the well formation had been totally cored and from which cores porosity determinations have been made as to effective porosity. There had also been fair-sized pieces of porous formation that had been blown out of gas wells and porosity measurements had been made on these as to the effective porosity. These pieces of formation were blown out of the holes after the completion of the well. (Vol. XCII, pp. 14108-14110.) The producing formations in the Turner Valley field are found in the Permian limestone which is similar in geological age to the limestone in the Texas Panhandle Field and is similar to such limestone in all respects. The average effective porosity of the field is about 15%. (Vol. XCII, p. 14106.)

Determination of Thickness of Gas Pays

Gill stated that the average pay thickness of 70 feet applied by Thompson to the commercial gas acreage is in his opinion a close approximation of the actual average pay thickness. This figure was reached after a careful study of records of some 500 or 600 gas wells in the field. The witness states it is rather significant and highly important in confirming the accuracy of this figure that Peterson arrived at an almost identical conclusion as to the thickness of pay, as a result of his own independent studies of about the same number of wells. Thompson's and Peterson's estimates of pay thickness differ in detail. The list of wells employed by them were far from identical. Each used wells on which

he, individually, was able to secure what he considered reliable information. On the wells which were used by both there are, in some instances, differences in interpretation. Decision as to the actual thickness of pay is in many cases largely a matter of judgment, and Thompson's and Peterson's opinions as to a considerable number of particular wells have been somewhat different. Each arrived, however, at almost identical figures for the average thickness of pay over the entire million-acre commercial area, and this fact very strongly supports the opinion of the witness that this figure closely represents the actual average pay thickness. (Vol. XCI, pp. 14013, 14014; Exhibit 265, pp. 31, 32.)

The witness testified on cross-examination that he had studied the porosity and pay thickness in the Texas Panhandle Field over a period of years—about five and a half years; that he had probably not spent more than fifteen days actually in the field, but he had spent a great deal more time than this with records and calculations in the field. He never made an actual determination of pay thickness in the Texas Panhandle Field but he has studied the method utilized in determining pay thicknesses and has done enough spot checking and examination of records and logs on his own account to satisfy himself. He has checked a considerable number of wells used by Thompson in the determination of his pay thickness, particularly the wells of Texoma, and calculated the pay thickness of a good many of them independent of Peterson, and the spot checking which he had done was sufficient to satisfy him that both Peterson and Thompson had made good estimates of pay thickness. In spot checking pay thicknesses he utilizes logs principally. He also had drilling tickets in some cases. (Vol. XCII, pp. 14140-14146.) He has spent an aggregate of five or six days in checking the thickness determinations of Peterson and has checked a number of wells he had used, being enough to see how he arrived at his figures in order that the witness might determine whether the estimates were good. (Vol. XCII, pp. 14148, 14149.) The witness also spot checked quite a few of Thompson's pay thickness determinations from Thompson's cards, which were wells that Thompson believed he had used in his determination of pay thickness. He discussed the determinations of pay thickness with both Peterson and Thompson and discussed particular wells with them. (Vol.

XCII, pp. 14174, 14175.) The witness did not take Thompson's cards and attempt to compare the pay thicknesses shown thereon against Peterson's pay thicknesses for the reason that there was no point in doing so. This would merely constitute "piddling around with picayunish detail that doesn't help in arriving at a conclusion." The fact that Thompson and Peterson differ on a particular well isn't important when their final averages come out almost identical. That shows that errors have compensated and balanced. One of the two is in error where one has more pay thickness than the other on a particular well. Maybe both are in error but the fact that the averages are substantially identical shows that those errors have compensated and it seems to the witness that this would show an open-minded man that the two of them were certainly not working together. The determination is not the pay-thickness of a particular well but their estimate of pay thickness for the entire producing area. Peterson and Thompson independently arrived at what witness considers to be a very, very sound and reasonable estimate of the average pay thickness for the Texas Panhandle Field. (Vol. XCII, pp. 14198, 14199.) The witness accepts the pay thickness, as determined by Thompson and Peterson, but stated very positively that he did not adopt either Thompson's or Peterson's thicknesses as to each individual well in specific detail, but does accept their averages as being very reasonable averages. (Vol. XCIII, pp. 14275, 14276.)

Determination of Recovery Factor

Thompson used a 90 per cent recovery factor based upon his opinion as to recoverable gas reserves. As to this factor Gill testified that there may be considerable difference of judgment. 90 per cent is a very high recovery factor for a gas reservoir, but may be justified for the Texas Panhandle Field as a whole, since trapping by water, which is a common cause of loss of recovery in many of the gas fields, will have less effect on recoveries out of the Panhandle reservoir. It is his opinion that the use of a somewhat lower recovery factor might be proper in a volumetric estimate of this type and that the use of any higher recovery factor would be entirely out of line and improper. (Vol. XCI, p. 14015; Exhibit 265, p. 32.)

Relationship of the Open Flow of Wells to Reserves in Place

Hughes employed a method in estimating reserves that is based upon an empirically established relationship between initial natural open flow, corrected to virgin pressure conditions, and per acre reserve of recoverable gas. The method and factors employed by Hughes have been devised and determined by him during some fifteen years of constant observation and study of the Texas Panhandle Field.

Gill had been familiar with Hughes' procedure for something over five years and had spent a great deal of time discussing it with him. The witness stated very positively that Hughes had developed his method by very careful and conscientious study and that he had availed himself of every possible opportunity to subject his procedure to careful and unbiased, critical, scientific scrutiny. Although Hughes' procedure originated in the Texas Panhandle Field, through his comparisons between open flows and estimates of reserves arrived at on a volumetric basis, a principle is incorporated which has long been recognized in the oil and gas industries. Experience over a long period of years and through the production of billions of barrels of oil and trillions of cubic feet of gas has shown that there is a close relationship between initial unrestricted productivity and ultimate production recoverable from a field or area. The principle is recognized in the proration orders of state regulatory bodies, which include in most of their allocation formulae a factor of potential production. It is also common practice in many areas to base valuation of oil producing properties for purposes of ad valorem taxation upon the rate of production. Prior to the application of extreme production curtailment under proration, purchase and sale of producing properties was commonly based upon rates of daily production. In all of these cases there is recognition of the general belief that a large producing well must be backed up by substantial underground reserves, and that a small well of inferior producing ability definitely indicates an area in which the underground reserves are small. (Vol. XCI, pp. 14016, 14018; Exhibit 265, pp. 34 and 35.)

~~The witness has on~~ several occasions made rather detailed studies of the actual relationship between initial production and ultimate recovery in the case of oil fields. Although com-

parisons cannot be made between different fields on this basis, he has found in a number of cases that within a particular oil field the quantities of oil actually recovered from different leases and from different parts of the field was on the average quite strongly related to the initial unrestricted potentials of the wells. The witness would expect the relationship to apply more closely to gas properties than to oil properties, since the performance of a gas well reflects conditions over a considerably wider area than does the performance of an oil well. Hughes has established the fact that in the Texas Panhandle Field there is a definite, and on the average, a remarkably consistent relationship between initial open flow of wells and the per acre reserves of gas estimated by the application of volumetric methods and pressure-decline methods. Although individual wells and properties may diverge from the average, these departures are the exception rather than the rule and the agreement between Hughes' procedure and other methods of estimation is close. Hughes is currently using a multiplier of .919211 to convert from open flow to per acre reserve. This multiplier expresses the slope of a straight line curve of the average relationship between open flow and underground reserves. The application of this factor to a map zoned largely on corrected initial open flows results in Hughes' estimate of field total reserves. (Vol. XCI, pp. 14018, 14019; Exhibit 265, pp. 35, 36.)

There are two theoretical factors concerned with well performance, which may well be considered in connection with Hughes' procedure of estimation. The first of these is Hughes' use of natural open-flows, corrected substantially to virgin reservoir pressure conditions. The witness feels that Hughes is entirely correct in applying these open flows rather than open flows at completion pressures or open flows after shooting or acidization. Hughes corrects completion open flows to virgin reservoir pressures by the application of back pressure curves of average slope. On the average this procedure will lead to a reasonably accurate estimate of what would have been the natural open flow of a well drilled at the particular point before pressures had been reduced by withdrawals of gas through other wells. This so-called virgin natural open flow will bear a closer relationship to reservoir conditions than will the open flow

at a partially depleted pressure or the open flow after acidizing or other treatment, which increase open flows by their effect upon permeability of formations closed to the well bore. Such increases do not truly reflect conditions in the area tributary to the well. (Vol. XCI, pp. 14019, 14020, Exhibit 265, pp. 36, 37.)

The witness further testified concerning this subject on cross-examination and stated that he had discussed with Hughes many of his calculations and the data upon which they are based and that although he is not at all certain that Hughes is absolutely correct in everything that he has done, he has arrived at a reasonably consistent method which is pretty well sustained. He has checked it by applying pressure-decline to limited areas that are in his opinion relatively free from influence of drainage and in some cases to subdivisions of areas, and in applying the pressure-decline test he weighted area and per acre content. This does not mean that he had his answer before he started. It is merely a method of checking the procedure and it is a very simple engineering procedure to check the validity of an answer of that kind. It is simply that you work the same thing two ways and come out with about the same answer. It serves as a double check on the procedure; for example, you can take the pressure-decline and figure back to a per-acre content.

You can also take the factor which Hughes used and calculate over from his zoning and the open flows of the wells in the zone to an acre content. If the two came out just about the same it would mean that the two were giving results that were in reasonable conformity. If one method consistently gave results that were higher than the other that would lead to a revision of the constant or multiplier (factor). Hughes arrived at the per acre content by the application of his factor against his open flow zone. He could then have applied, and in some cases did apply, the pressure-decline method in the limited area with which he was dealing, and weighted out the pressure-decline on that area and the per acre content and arrived at such weighted pressure-decline for the area. He started with a per acre content and he weighted the pressure-decline per acre to arrive at a weighted pressure-decline. Then in many cases he took the per acre content which he calculated by the

application of a factor, and combined these two and reached a figure for the total reserve of the area with which he was dealing. He could then apply against that estimated reserve at the beginning of his period the amount of production that had come out of the area during the period for which the pressure-decline was determined, and from that could have calculated from the production and the original reserve what the pressure-decline should have been. He would then have arrived at two independent figures for the same pressure-decline. One of them resulted from taking the surface pressures and weighting by area and per acre content, and the second, by relating his estimated original reserve to the withdrawals to reach a pressure-decline. If his estimate of per acre content was correct those two methods would give exactly the same figure for pressure-decline. If they wound up with different answers that would mean that his factor was probably wrong. If, over a series of such checks, there was a consistent trend shown, that is, if it showed that his estimates of per acre reserves were consistently high—consistently too high—to make those calculations come out even, then it would be time to revise the factor. The witness has seen his calculations on these various areas and has gone over a considerable part of the data. The witness believes that an independent application could be made of the pressure-decline method and, if made on the same area from the same data, and made honestly and competently, it would check with Hughes' estimate of reserves. The true weighted average pressure could be determined approximately by weighting pressures on surface area alone where applied to a zone, as Hughes did, where the per acre content was substantially equal throughout the zone. There are only two sets of conditions under which a pressure average on surface acreage alone can truly represent actual average pressures, that being when the pressure is equal in all parts of the reservoir or when each and every acre in the reservoir is underlaid by exactly the same volume of gas bearing voids. Mr. Hughes approached that second condition when he limited his calculation to an area in which, in his opinion, the reserve under one acre was about the same as the reserve under every other acre. Therefore, he weighted the pressures within that particular zone on surface acreage alone and got approximately an average weighted pressure on volume for that zone. He then took the next zone and

treated that separately. He didn't try to combine the two. This will serve as a sufficient check upon the field as a whole if applied to enough areas. Hughes extended that check pretty well over the whole field. The witness has gone over Hughes' work and believes that his zoning of the field is within reasonable limits of accuracy. (Vol. XCII, pp. 14183-14187, 14189-14191, 14193-14196.)

Witness explained that when he said that Hughes' zoning of the field was within reasonable limits of accuracy he had in mind that there was some error inherent in such studies. The more thorough the studies and the more thorough the data, the less the error becomes, and as time goes on the estimates get better and better and more accurate. Hughes' estimates of reserves of the Texas Panhandle Field have varied perhaps ten per cent as his data and checking and weighting of the thing lead his opinion to be improved upon and to be grounded upon sounder and sounder results. That is a common engineering practice where the accuracy of results is limited by the extent of the data available. Hughes' estimates have been developed over a period of years by continuous study testing and weighing and improvement to arrive at his best opinion as to the reserves. It is the witness' opinion that his estimate of reserves is pretty close to the actual facts. (Vol. XCII, p. 14196.)

The witness further testified on cross-examination that all of the wells shown on Exhibit 212 were not corrected back to virgin open flow conditions but the ones where the corrections amount to a substantial amount have been corrected back. Many of the wells were completed close to virgin pressure and the correction was so small in those wells that it wasn't necessary to make the correction. The witness knows this to be a fact because he contoured a couple of maps of the Texas Panhandle Field based upon corrected virgin open flows and is familiar with those figures. The witness checked Hughes' zoning of the field as detailed on map sent him in 1938 or 1939. The map he checked was not colored but it did have potentials noted on it. He checked those potentials against the Railroad Commission's open flow potentials as of that date, which he corrected back to virgin open flow in order to determine if they were in reasonable correspondence. No corrections were made in the high pressure areas because the figures used by Hughes

were close to the open flow figures of the Railroad Commission's report and therefore they were considered to be about right. The witness stated that he knew all the open flows recorded on the map, Exhibit 212, were not initial open flows at virgin pressure but that there are a sufficient number of them to support an estimate of reserves. Some of the open flows on the map don't mean anything, particularly because many of them are incorrect open flows that have been reported on the initial completion of wells and where the initial reports were erroneous these wells were not used in determining the averages. (Vol. XCII, pp. 14200-14204.)

Hughes' method will work whether he has the initial virgin open flow of every well or not. It would work just as well on most any type of uniform correction of open flows in order to make the open flow figures which he used for different parts of the field comparable with each other. The principle would apply just the same. His factor is based upon the study of factual relationships upon the field and is determined by that. (Vol. XCII, pp. 14205, 14206.)

It is the opinion of witness that it does not necessarily follow that a 10 million foot open flow represents approximately 10 million cubic feet of gas per day in place, but that he does think that this ratio is approximately correct in the Texas Panhandle Field. The witness bases this conclusion upon studies he has made which have led him to believe that the relationship stated by Hughes is approximately correct. The witness has made a good many studies of this in the Texas Panhandle Field and has made a good many studies of the work that Hughes has done and he has studied the work of other people. This conclusion is not based solely upon what Hughes did but, as stated, the witness has made a number of studies and has made independent personal estimates of the total reserves of the Texas Panhandle Field from which he learned a great deal. He has examined specific data on a large number of wells in the field. He is familiar with the performance of gas reservoirs in general, including the Texas Panhandle Field, and he bases his opinion not on any one part of his various studies, but on the whole. (Vol. XCII, pp. 14206-14208.)

The witness and those working under him spent at least a thousand man-hours of work on checking Hughes' zone

map in early 1939 (the predecessor of the present map). They calculated back and checked every one of the open flows shown on the map. That is, corrections were made in open flows where the well was brought in at a pressure so low that the correction was of importance. The witness and the men working under him took one of the maps and checked the potentials all the way through and contoured the map on virgin open flow potentials and made many calculations from them. They found the potentials on the map to be quite reasonably accurate when compared against the Railroad Commission's records. The map was checked against the latest report of open flows from the Railroad Commission, well by well. (Vol. XCII, pp. 14220-14223.)

The map that the witness checked was the one submitted by Hughes in the Texoma case and every well on the map was checked and the data were found to be reasonably accurate. (Vol. XCII, p. 14224.) (Hughes has heretofore testified that the map, Exhibit 212, is the same map that was submitted in the Texoma case, Vol. LXXVIII, page 11491).

TY

Permeability as Related to Porosity

Gill testified on direct examination that the theoretical considerations bearing on the propriety of using open flow as a measure of reserves in place are rather complicated. In the simplest sense they are compared with relationships between permeability and porosity. Technically porosity and permeability are more or less inter-related but are not mathematically determined as to value by this relationship. The theoretical relationship between porosity and permeability is rather qualitative in nature, and may be expressed by the statement that permeability cannot exist at all in the absence of porosity, and that effective porosity, which may be loosely defined as that porosity from which fluids can be withdrawn into wells, cannot exist at all in the absence of permeability, since permeable interconnection is necessary in order to make the porosity effective. As a practical fact the relationship between porosity and permeability is much closer than this generalized statement might indicate. Within a particular pay formation it has been found, in many cases, that there is a rather direct relationship between permeability and porosity. This statement applies to aver-

ages, and many individual specimens will show relationships that vary either way from the average. In general, however, it is true that within a particular field a definite relationship between permeability and porosity frequently exists. (Vol. XCI, pp. 14020, 14021; Exhibit 265, pp. 37, 38.)

Permeability is not by any means the only factor which determines the open flow of a gas well. Although high permeability in the part of the formations immediately surrounding a well bore is necessary for a well of large open flow, there are conditions under which such high local permeability may not result in a large well. For example, the well bore might encounter a small local area in which the reservoir rock was extensively fissured or contained very large, continuous pores. If this were only a local condition, and if the large fissures or pores were fed by a formation of extremely low porosity, the well would not be able to sustain a high rate of open flow, since gas could not be fed rapidly enough to the local spot of high permeability. A high, sustained rate of flow for a gas well is possible only when the formation tributary to the well contains a large volume of gas. The volumetric content of the reservoir formation, which is one of the controlling factors in open flow, is dependent upon the thickness and porosity of the porous formation. (Vol. XCI, pp. 14021, 14022; Exhibit 265, pp. 38, 39.)

* * * * * *

Stanley Gill also testified on cross examination (Vol. 92, pp. 14140-14146; 14179-14181) as follows:

Q. Have you ever made an estimate of reserves of the Texas Panhandle field?

A. I have made a good many of them.

Q. Where are some of them? Have you ever put them in evidence in a case?

A. No, sir.

Q. Have you ever made them for a company and furnished the company with a copy of it?

A. I have furnished Texoma with the results of a good many of them. What I have attempted to do is to make a proper application of pressure decline methods for the Texas Panhandle field by various methods of weighting and by various methods of calculation, and each time I have made such an estimate I have weighed that estimate as impartially as I have tried to weigh the estimates that have

come into this case and have decided that they were not good.

Those estimates have ranged from 22 trillion to 34 trillion, depending upon the methods that were used. None of them have stood up under my own analysis where I would be willing to accept them as correct estimates.

You understand, Mr. March, the treatment and analysis of these declines that I have applied to the estimates of Mr. Hammer and Mr. Stevens aren't something that I have invented for this case. I have been using it against my own estimates for many years.

Q. Well, you can't—you never had—

A. They are my own estimates and if my own estimates fail to stand those tests I discard them.

Q. You have never testified in a case in which you have made an estimate of the reserves of the Panhandle field of Texas?

A. Of course not, because I have never made an estimation that stood up, when I tested it impartially, and I have never made an estimate that I considered myself was a truly correct estimate.

Q. Why didn't you try the porosity thickness method?

A. I considered that the use of the porosity thickness method which had been made by Mr. Thompson and Mr. Peterson was far better than any application I could have made of it because of their far greater experience and knowledge of the field. I, therefore, did not waste time on trying to make a porosity thickness estimate which would have been in my opinion inferior in quality to the ones that they had made.

Q. Well, if you have never made a study of the application of the porosity thickness method in the Panhandle field of Texas of your own, how do you know that theirs is right?

A. I didn't say I had never made a study of that method in the Texas Panhandle field, Mr. March. I have, and I have over a period of years.

Q. How many years?

A. Well, it's a little arithmetic—about five and a half years.

Q. How much time have you spent in the Texas Panhandle field during the last five and a half years?

A. I don't suppose during the last five and a half years, I don't suppose actually, physically, I have spent over fifteen days in the Texas Panhandle field. I have spent a darn sight more time than that with records and calculations on the field.

Q. Furnished to you by Mr. Thompson and Mr. Peterson and Mr. Hughes?

A. Some of the information.

Q. Did you have it furnished by anyone else?

A. Yes.

Q. Who?

A. Well, I had a considerable amount of data from Phillips Petroleum Company.

Q. What sort of data?

A. Well logs, principally.

Q. Have you got those?

A. I had pressure tests; I had a mass of information from the Railroad Commission of Texas.

Q. Did you ever make an examination of the pay thickness and the porosity of the Texas Panhandle field?

A. As I told you, I have studied that method and I have done enough spot checking and examination of records which —both on my own hook—of logs and more particularly with Mr. Peterson and Mr. Thompson so that I am personally satisfied to accept their estimate of thickness.

Well, that's what I have done from my own studies of this method.

Q. Did you ever try to make an estimate of thickness of the Panhandle field of Texas yourself?

A. Mr. March, I don't like to have to tell you the same things over and over. I have spot checked their methods but I have never myself made an estimate of average pay thickness over the entire Texas Panhandle field.

Q. Have you ever spotted the wells that Mr. Peterson uses on a map of the Panhandle field of Texas?

A. No, I never have.

Q. Do you know how many wells Mr. Peterson uses?

A. Something over 600.

Q. Have you ever made an examination of any of those wells to check them?

A. Of a considerable number, as I said.

Q. Which ones have you checked?

A. I don't remember, Mr. March.

Q. Can you name one that you have checked?

A. Well, I have checked with Mr. Peterson practically every one of the Texoma wells. I would say every one of the Texoma wells that were drilled prior to 1936 and most of them that were drilled from 1936 to 1939.

Q. Did you check the pay thickness calculations?

A. Now, if you want me to, I'll read the names of those wells.

Q. That is a list of all the Texoma wells?

A. That's right.

Q. Well, there is no need to read the list. You have designated them sufficiently clear, but I will ask you this:

Did you, independent of Mr. Peterson, calculate the pay thickness for those wells of Texoma?

A. A good many of them.

Q. Well, how many of them?

A. I don't know.

Q. Which wells did you calculate the pay thickness for that Mr. Peterson used?

A. I told you, Mr. March. I thought I made it clear that I had done enough spot checking to satisfy myself that both Mr. Peterson and Mr. Thompson, independently, had made what I considered good estimates of pay thickness. Now, I have used that pay thickness only a very general way. I think the pressure decline method is a much better method of estimating reserves than pay thickness when it is properly done.

Q. Of the Texas Panhandle field?

A. Any field, and of course it is terribly bad when it is improperly done.

* * * * *

Q. You testified in the Texoma case in your examination, I believe, by Examiner Simpson, on Page 1512 and 1513:

"By Mr. Morgan:

"Q. Can that method of computing reserves be applied to the Texas Panhandle field, Mr. Gill?

"A. I think it is possible to apply it by weighting to a per acre content of the field, which is essentially what Mr. Hughes did in arriving at his constant. That is, he weighted his pressures both to area and to per acre content in order

to arrive at an average pressure. I think you get a fair approximation that way."

You were speaking there of the pressure decline method as applied by Mr. Hughes. There your testimony is. Is that correct?

A. I presume so.

Q. Well, now, what pressure decline method of Mr. Hughes were you talking about?

A. It is stated exactly there.

Q. I see. Well, how did he apply it there?

A. It is just stated in what you just read, Mr. March. This is from Page 1513 where you were reading:

"That is, he weighted his pressures both to area and to per acre content in order to arrive at an average pressure. I think you get a fair approximation that way."

Now, that explains just exactly; that is, by combining both as to area and as to per acre content he did get a weighting on volume, a sort of weighting on volume, a fair approximation, as I have called it there. He did get a fair approximation of a weighting to volume of gas.

Mr. Gill further testified (Vol. 93, pp. 14254-14257; 14259-14263; 14267-14268; 14270-14272) as follows:

By Mr. March:

Q. I will refer you to Page 42 of your written statement, Exhibit No. 256—265, where you state:

"Not only do such withdrawals bring about extensive drainage, but they are of importance in controlling future trends of withdrawals. For example, heavy withdrawals of gas from Wheeler County may be expected to lead to premature reduction of pressure, and to a shift of withdrawals into the sweet gas area of Moore County."

Now, I want to know what study you have made to ascertain whether or not there will be a shift of the operations of the companies producing in the east field to the west field.

A. Oh, that isn't based on a detailed study. It is just a matter of common sense and common knowledge. It is an inevitable thing.

Q. How do you know they won't go to some other field?

A. Well, it's just that that is the most reasonable expectation. There is no—there will be a rather strong incentive to stay in the Panhandle because of the fact that to a considerable extent the trunk line and gathering line investments have already been made and as long as there is gas in the Panhandle it will to a considerable extent be more economical for those people who are now getting their supplies out of the east field to remain in the Panhandle than it would be for them to jump off into some other field which might require considerable additional trunk line investment.

Q. Isn't it quite probable that some of them will go out to the Hugoton field?

A. I don't know about the Hugoton field specifically but I think it is quite probable that some of them will get some of their supply from other fields when the east field won't supply them any further, but on the other hand I think it is absolutely certain that part of the demand now satisfied out of the east field will be taken up out of the west field when the east field production peters out.

Q. Don't you know that some of these companies producing gas out of the east field at the present time have large holding in the Hugoton field immediately north of the Panhandle field?

A. I understand that they do, and it is also true that some of the companies in the east field could reach up into the west field far less expensively than going to Hugoton.

Q. Well, isn't the acreage pretty well taken up already in the west field?

A. Generally speaking, yes, sir, but there is acreage which is not now connected.

Q. I thought it was your general opinion the whole field would be pretty well depleted at the same time.

A. Did you?

Q. Yes. Is it?

A. I wouldn't know—I wouldn't say that that question expresses my opinion at all. I wouldn't say so, no sir.

Q. You think that there will be certain parts of the field depleted before other parts of the field are?

A. Certain parts will be depleted for particular purposes long before other parts are; that is, I believe, for example, that the east field will be depleted as far as it being a source

of supply for trunk pipe line purposes considerably before the extreme high pressure area of the west field there.

Q. If there is a free movement of gas and drainage into the Panhandle field, why wouldn't the gas drain from the west field into the east field and maintain the pressure in the east field?

A. Mr. March, you asked me about that yesterday and I told you there was no effective sub-surface drainage between the east field and the west field.

Q. Do you think as a practical matter there will be?

A. As a practical matter, I don't think there will be a drainage between the east field and the west field.

Q. What is the estimate of reserves as a whole?

A. For the reasons stated on Page 42 and the excerpt you read from Page 65, that is, that depletion of the east field will result in a shift of withdrawals into the west field, and that, therefore, the reserves in the east field will have a bearing upon the eventual depletion of the entire Texas Panhandle field.

Q. When do you think this shift will take place?

A. I don't know. I haven't figured it out. It won't be so long until there will be some shift.

Q. Do you know how near the east field is to the depletion?

A. No, sir, I haven't made a reserve estimate of it. The pressures are coming down over the entire east field.

Q. Do you know in the east field there are pressures still over 400 pounds?

A. Yes, in two places in very lowly productive areas, areas of low productivity of no commercial importance as far as I know.

* * * * *

Q. Now, beginning on Page 7 and extending through Page 40 of your exhibit, as I understand that is where you start your criticism of Mr. Hammer and Mr. Stevens.

A. My discussion of their estimates, yes, sir.

Q. Now, let's first hurriedly run through here beginning on Page 7. When you weight the surface don't you have to take volume into consideration automatically?

A. No, sir.

Q. Isn't there a relation between surface and volume?

A. As I told you yesterday, surface is one of the factors

in determining volume. It is exactly the proposition if you would say that the volume of a carpet covering the floor of this room was the same as the entire volume of the room. Obviously, it isn't anything of the sort, but that is what you do in weighting pressures in a reservoir when you weight it on surface acreage alone. You say that the volume of the carpet covering the entire floor of this room is exactly the same as the volume of the entire room. That is why it is wrong.

Q. You say here: "Mr. Hammer's pressure decline method in which withdrawals of gas are compared to declines of pressure, the latter being weighted only on surface acreage, is entirely incorrect for estimation of reserves of gas in the Texas Panhandle field."

All right, now, Mr. Gill, how much incorrect is Mr. Hammer?

A. Well, it is my opinion that his estimate of total original reserves is something over 50 per cent high.

Q. How much?

A. Something over 50 per cent high.

Q. How do you know? You haven't made an estimate.

A. I have made many estimates of reserves of the Texas Panhandle field.

Q. You stated they were all wrong?

A. Yes, sir

Q. All right, then—

A. I made estimates as wrong as Mr. Hammer's.

Q. Have you ever made an estimate you thought was right?

A. No, sir.

Q. How can you measure anyone else's estimates? What do you have to go by? What standard do you have to go by?

A. I testified yesterday, Mr. March, at rather exhaustive length that I have made many estimates of the Texas Panhandle field; that I had weighted them generally as correctly as I had weighted the estimate of reserves discussed in Exhibit 265, and that in every case where I had made an estimate of reserves by any one of the various applications of pressure decline procedures they had failed in the light of analysis on the basis of what is happening in the field to prove up to be correct. In other words, they failed under

analysis just as Mr. Hammer's estimate failed under analysis and for similar reasons.

Now, in the case of some of those estimates they didn't miss the material as badly as Mr. Hammer's estimate does, and—

Q. How do you know he missed it at all?

Mr. Keffer: Let the witness finish.

Mr. March: I beg your pardon.

The Witness: And in others cases they missed it as badly as Mr. Hammer did. As I told you yesterday, the estimates I have made have resulted in estimates of original reserves from 22 trillion up to 34 trillion, I believe, and in general the lowest estimate, say from 22 trillion to 25 or 26 trillion, comes closer to checking out than the higher estimates.

I have explained it at a great deal of length in this discussion, which is incorporated in Exhibit 265, that in view of the fact I have not yet been able to work out the proper application of pressure decline to the field, I am of the opinion now that the best estimate of reserves that are available on the Texas Panhandle field are estimates Mr. Hughes and Mr. Thompson have introduced here. I don't accept their estimates as absolutely correct, but I think they are the best estimates there are. My own work leads me to the opinion that the lowest estimates I arrived at which were on the order of 22 trillion for original reserves, were too high, and, therefore, I believe in my own work that the true figure is below 22 trillion; and as I say, I now am of the opinion at the present time that the figures which have been presented by Mr. Thompson and Mr. Hughes and which lead to figures less than 20 trillion, are of the best available

Q. Are they within 20 per cent of correctness?
A. Oh, yes, they are probably closer than that.
Q. How much closer than that?
A. I don't know.
Q. You don't know?
A. No, sir.

* * * * *

Q. It is your position that Mr. Hammer has not con-

tended that it would be possible for the Canadian River to recover these reserves?

A. I have made no such statement, Mr. March.

Q. You don't purport to make any such statement?

A. I haven't said that Mr. Hammer doesn't have the idea it wouldn't be physically possible for Canadian River to recover the quantity of gas under their properties. I think it could be said that it would be physically possible for them to do it but to attempt to apply that to a practical situation is sophistry of the wildest sort.

Q. Have you made a study to ascertain how much they couldn't recover?

A. I have made a rather thorough study of the probable drainage. I have not attempted to express it in quantitative terms—

Q. Can you at the present time in—

A. Let me complete my answer. I was going to state on the end of that answer that it was because I can't estimate it quantitatively.

Q. It is impossible for you to say just exactly how much of the remaining reserves under Canadian River's acreage that Canadian River will recover or not recover?

A. I think that is a correct statement.

Q. It is impossible for anybody else to say that?

A. Yes, sir, I believe so.

Q. Then you don't know if you can't measure quantitatively or cannot give any approximation of it quantitatively whether or not they could recover all of the remaining reserves under this acreage?

A. If we wished to indulge in pure sophistry I would say that Canadian River Gas Company could recover all of its recoverable gas now under its property. I don't know what in the world they would do with it, though. It would be necessary for them to move in and drill a lot of wells and blow a tremendous quantity of gas to the air or else put it up in cans and save it for future use.

As a practical matter, Canadian River will not recover anywhere near all of the quantity of gas that is now existing under that property. I know that, Mr. March, in exactly the same way that I know a louse is smaller than an elephant. However, I have never measured either one of them.

Q. It would do you good to measure them, wouldn't it?

A. No.

Q. You can measure the difference between a louse and an elephant, can't you.

A. I know a louse is smaller than an elephant.

Q. Can't you measure the difference?

A. Yes.

* * * * *

Q. Do you think when Mr. Hammer takes his quadrants and weighs in the surrounding quadrants and considers the *surrounging* quadrants in figuring each one of the quadrants he takes in to any effect his drainage which might take place in regard thereto?

A. Not to any practical extent. Now, that procedure which is a very poor and indefensible procedure, does have a tendency to take a quadrant from which gas has been drained and to indicate that the present reserve of that quadrant is greater than it actually is. To that extent it tends to erase, disguise and conceal the fact that drainage is taking place.

Q. I believe you admit here it is proper to divide the field up into quadrants in making estimates of reserves?

A. As a matter of convenience, yes, sir.

Q. It is a matter of convenience to divide the area up that way? You say, as I understand, those quadrants should follow zones of equal productivity?

A. I didn't say that.

Q. What did you say in regard to that?

A. I said they didn't follow zones of equal productivity or zones of anything else.

Q. You said they should if they were to be used at all, didn't you?

A. I don't believe so. He could have gained some information by having them do that, but I didn't say they should have.

Q. You said that Mr. Hammer's quadrants are not laid out in relation to pressure patterns, relative reserves or areal distribution of withdrawals.

A. What page is that on?

Q. That's on Page— and then you say—

Mr. Spencer: What page, please?

Mr. March: That's on Page 16.

Q. You say: "Up to the point of his determination of withdrawals and weighted pressures by 'quadrants,' Mr. Hammer has made legitimate use of his subdivision of the field area."

Now, did you imply there that when you do divide the field up into quadrants in estimating reserves that you should follow the pressure band—I mean the productivity bands?

A. No, sir, I didn't say that they should. That's what that statement means. He could have gained some information out of his subdivision by some such method of dividing, but he did not do it. I didn't state that he should have done it, Mr. March.

Q. Do you know what would have been the difference in Mr. Hammer's results if he hadn't weighed the surrounding quadrants in determining a given quadrant?

A. As to which one of the results?

Q. Any of his results—his results on the field as a whole.

A. I haven't calculated through, Mr. March, but I rather expect that his results for the field as a whole would have come out pretty close to what he got. That's just due to the accident of distribution as between his quadrants. It would be my idea that he would come out somewhere reasonably close to the same answer for the field as a whole.

Q. Why are you criticising his using the surrounding quadrants?

A. Because it is an entirely incorrect method.

Q. If he comes out with almost the same answer, why do you say the answer—why do you say it is an incorrect method?

A. As I said, I haven't figured it out—figured it through, but due to the accident of distribution it would probably come out to about the same answer but you see in arriving at the same incorrect result by two methods doesn't make it right.

* * * * *

Stanley Gill further testified (Vol. 99, pp. 15298-15300; 15347-15351) as follows:

Q. Now, Mr. Gill, if that area was formerly below 400

pounds and suddenly it became 400 pounds and over, what would you say was the cause of that?

A. I would say that if it did take place there would be some replenishment by drainage.

Q. Don't you think, Mr. Gill, there was drainage into the Canadian River acreage and repressuring here which caused the low pressure area to be wiped out of the middle of Potter County in 1937 and the 400-pound band even extended over into Moore County?

A. I really don't know, Mr. March. It is entirely possible that that particular part of Canadian River's acreage did pick up some gas out of other parts of Canadian River acreage. You see, geographically, that big high pressure area in Potter County from which much drainage would come in there is Canadian River acreage.

Q. Well, obviously, if any great movement of gas came about that way, there would be some low pressure created in a corresponding period of time in Canadian River acreage, wouldn't there?

A. I expect the pressure out in the yellow area was reduced somewhat.

Q. You notice here in 1937 there wasn't any low pressure areas created to the southwest of the repressuring area.

A. There isn't any pressure below 400 pounds shown on the 1937 map, no, sir.

Q. Now, Mr. Gill, have you made a study of that area in there to ascertain specifically the cause of that?

A. The study I have made, Mr. March, is to determine physically the cause of the overall sequence of development of low pressure back into that Moore and Potter County area. Very definitely that general overall development, although it is masked in spots by such local effects as you mentioned, is occasioned by the large regional drainage of gas out of that area into the area of very heavy withdrawals which lie in general in southwestern Hutchinson County.

Q. My question to you is specifically this: Have you made a study specifically of the production by wells to ascertain the cause of that repressuring in Potter County in 1937 and in a part of Moore County?

A. I have answered that question several times, Mr. March.

Q. What is your answer?

A. The only specific study by wells in relation to drainage trends that I have made is one, the results of which are tabulated on Page 10, Exhibit 266. That shows very positively that area to which you are referring has suffered rather extensive drainage.

I have also included in Exhibit No. 266 some calculations that I have made from Mr. Hammer's data as to his quadrants which show the same thing, and—

Q. I know. That is in the record. There wouldn't be any drainage indicated from this area in 1937 when the area was repressuring, would there?

A. There is extensive drainage out of Potter County and southern Moore County indicated by the sequence of development of low pressures in that area which is shown by this series of maps, Exhibit 239, from year to year. It is a progressive thing and—

• • • • •

By Mr. Gibson:

Q. Mr. Gill, have you by your Exhibit 265 made or attempted to make an estimate of recoverable reserves of the Texas Panhandle field?

A. That particular exhibit does not include an estimate of reserves made by me; no, sir.

Q. The same is true with respect to the Canadian River Gas Company's properties in that field?

A. That is right, yes, sir.

Q. In preparing this exhibit I notice under the heading "Scope of Study," you have stated: "I have been requested to prepare and to submit a report covering my opinions and conclusions as to the several estimates of gas reserves in the Texas Panhandle field, which have been presented in this proceeding. In compliance with this request I have studied the exhibits and testimony relating to the estimates of reserves listed below:"

Then you list the estimates, some ten of them.

A. There are four estimates of reserves.

Q. Four estimates of reserves?

A. Yes.

Q. On Page 5 under the heading "Introduction," you

make the statement: "Attention has been given to the correctness of methods employed, to the manner in which they have been applied and to the applicability of the results in determining the future producing life of gas reserves in the Texas Panhandle field."

On the same page you state: "While it must be understood that estimation of reserves of gas or oil is far from being an exact science, it must also be emphasized that reasonably accurate estimates can be arrived at by the application of proper methods."

On Page 6, in speaking of the estimation of reserves you state: "The results are 'estimates' rather than 'determinations' of the reserves of oil or gas."

On Page 7, in dicussing the estimate of Mr. Hammer, you make the statement: "Mr. Hammer has made his estimate of reserves of gas in the Texas Panhandle field by a pressure decline method which involves several unique features. I feel that Mr. Hammer's estimates are neither correct nor applicable for evaluating the probable future life of the Canadian River or field reserves. This opinion is based upon three lines of reasoning:"

I desire to ask you in this connection if it is not a fact that by this exhibit, that the only thing you have done or attempted to do is this: Instead of taking the data shown in the exhibit of Mr. Hammer and using it for the purpose of making an independent estimate of recoverable gas reserves of the Canadian River's properties, you have taken that exhibit and given it a critical study for the sole and only purpose of arriving at your conclusions and stating your opinion with respect to the correctness or incorrectness of the inference made, the conclusions deduced, and the opinions stated by Mr. Hammer in the making of his estimate?

A. That question is involved, Mr. Gibson, but I will refer you back to the quotation which you read from Page 4 as to the scope of the study. I have done exactly what I stated there; that is, I have prepared and submitted a report covering my opinion of conclusions as to the overall estimates of gas reserves in the Texas Panhandle field

which have been presented in this proceeding. That is what I have done.

Q. An estimate constitutes nothing more or less than a formulation of opinion based upon data, opinions, theories, and judgments; isn't that a fact?

A. Yes, sir, I would say that is correct.

Q. Then it is true that the only thing you have done is to take the data, the observations, the theories, the judgments, the inferences, conclusions, and opinions stated by Mr. Hammer and the others in these exhibits and after having made a study of the same you have arrived at your conclusions and formulated and stated your opinion respecting the correctness or incorrectness of the inferences, conclusions, or opinions stated by them?

A. I have expressed my opinion as to the correctness of their results and have detailed my reasons for arriving at those opinions. That is what I have done.

Q. That is all you have done or pretended to do, is it not?

A. I have done what I stated here in this report that I intended to do, yes, sir.

Q. What is said with respect to Mr. Hammer applies likewise to all you have mentioned in your exhibit?

A. I have studied the estimates and arrived at the conclusions stated in my Exhibit 265.

Mr. March: Is that all, Mr. Gibson?

Mr. Gibson: No.

Mr. Spencer: Are you through with your cross examination of this witness?

Mr. Gibson: Yes.

Mr. March: I have one other question I would like to ask the witness and Mr. Keffer has a few on redirect.

Mr. Gibson: At this point I want to make a motion to strike this exhibit and everything that is said with respect to it.

Analysis of Pressure Decline Method of Estimating Natural Gas Reserves in Texas Panhandle Field.

A. Basic Principles:

"Boyle's Law expresses a simple relationship. It states the fact that the quantity of gas contained within a rigid container varies directly with the absolute pressure. Doubling the pressure doubles the quantity of gas. By increasing the pressure ten times, ten times the quantity of gas can be stored within the container * * *. This law applies strictly to the perfect gas, regardless of the size or shape of the rigid container in which it is confined. Correct calculations can be made from it, however, only when the actual pressure average throughout the entire volume of the container is accurately known." (Gill—Exhibit 265, page 9.)

"A pressure-decline method in which withdrawals of gas are compared to declines of pressure, the latter being weighted only on surface acreages, is entirely incorrect for estimation of reserves of gas in the Texas Panhandle Field." (Gill—Exhibit 265, page 7.)

"According to Boyle's Law pressure varies with volume and not with area unless each area happens to contain the same volume." (Hughes—Exhibit 258, page 6.)

"Volumes (of gas) are not equal in the various areas of the (Texas Panhandle) Field." (Hughes—Exhibit 258, page 11.)

"Hammer * * * has weighted his pressure against areas and not against volumes. * * * he does not have uniform volumes per acre for each quadrant and neither does he have uniform pressures for each quadrant." (Hughes—Exhibit 258, page 11.)

B. Illustrations of Use of Pressure Decline Method in Estimating Natural Gas Reserves:

Testimony of C. Don Hughes
Witness for Canadian.

C. Don Hughes, Witness for Canadian, testified on this subject (Vol. 86, pp. 13086-13121), as follows:

Q. Your name is C. Don Hughes?

A. Yes, sir.

Q. You are the same C. Don Hughes who has testified before in this case?

A. Yes, sir.

Q. Mr. Hughes, I hand you a document and I will ask you if you prepared that instrument in Statement form as an exhibit to be utilized in this case?

A. Yes, sir, I did.

Mr. Keffer: I will ask, Mr. Examiner, that the instrument be marked for identification.

The Trial Examiner: It will be marked for identification as Exhibit No. 258.

(Exhibit 258, Witness Hughes, marked for identification.)

By Mr. Keffer:

Q. Will you proceed and read that statement Demonstration the Pressure decline method.

A. "In order to show how this method is based upon Boyle's Law we refer to Chart 1 where we have three containers of equal size, each containing 20,000 CF of gas, at a pressure of 400#, making a total of 60,000 CF of gas. All of the valves are closed.

Example #1. Suppose we open valves A, B, and C, and then we open valve D and allow 15,000 CF of gas to go out through meter X, in doing this 5,000 CF of gas is removed from each of the containers and, since 5,000 is exactly ¼th of the 20,000 content then the pressure drops ¼th or 100# in each container and the remaining pressure is 300# in each container, and the weighted average pressure is the same in all three.

Since the same pressure drop has occurred in each then that is the weighted average pressure drop, or 100#, and with a withdrawal of 15,000 the production per pound drop is 150 CF. Since our original pressure was 400#, then by

multiplying 150 CF per pound by 400# we get 60,000 CF as our computed original amount, which is correct. The correct result is reached because we had an equal volume in each container, and we are in effect weighting pressures against volume.

Example #2. Now, suppose we start out again with the full amount and with all valves closed, and we open valve A, then we open valve D and allow 15,000 CF of gas to flow out through the meter X, all of it comes from A. Since this ¾ths of the total amount originally in A then its pressure drop will be ¾th of 400#, or 300#, leaving a pressure of 100# in A.

Now, in order to compute the weighted average pressure remaining in the three we add their pressures, 100# in A, 400# in B, and 400# in C, and find the total of 900# and dividing by 3 find 300# as the weighted average pressure. Thus we see that the weighted average pressure loss is 100# and since 15,000 CF was produced it was at the rate of 150 CF per pound drop and multiplying by 400 gives an original content of 60,000 CF which again is correct. This is true because all of the containers have an equal volume and we are in fact weighting the pressure against volume.

Example #3. Now, instead of going back to the beginning, we start where Example #2 left off, we close valve A, open valve B, leaving valve C closed, then open valve D long enough to let 15,000 CF of gas be produced through meter X; this of course will all be coming from container B.

Since this is ¾ths of the total originally in B, then the pressure drop would be ¾ths of 400#, or 300#, leaving 100# pressure in B.

Now, to compute the weighted average pressure of the three containers by adding 100# in A, 100# in B, and 400# in C, we have 600# and dividing by 3 we find 200#. The weighted average pressure has dropped from 300# to 200#, or a loss of 100# with 15,000 CF produced, or 150 CF per pound drop, the same as before.

Multiplying by 400# we get 60,000 CF as original content, which is correct. By this time the grand total production from beginning however is 30,000 CF and with an

overall pressure drop of 200# making 150 CF per pound drop, we again multiply by 400# and get 60,000 CF as the original content; and again, this correct for the simple reason that we have weighted pressures against volume.

Example #4. Now we will carry on from where Example #3 left off. We close valves A, and B, leave C open and then open D long enough to produce 15,000 CF through meter X. Obviously all of this comes from container C and is ¾ths the original content of C hence C has lost ¾ths of its pressure or 300# leaving 100#. We now add 100# in A, 100# in B, and 100# in C, getting 300# and divide by 3 to find the weighted average pressure of the three to be 100#. The weighted average at the end of Example 3 was 200# so we see a drop of 100# during Example 4 with 15,000 CF produced, or 150 CF per pound drop, the same as in the other previous examples. Multiplying by 400# we find 60,000 CF as the original content, again it is correct for the reasons hereinabove stated.

Thus we see that in this setup where the containers are all of equal size we can apply Boyle's Law and get a consistent and correct amount of gas produced per pound drop whether the gas pressure in all containers is going down uniformly or whether it is going down differently in the different containers. Since the examples give the same amount of production per pound drop, then by multiplying by the same original pressure in pounds the computed original content always figures the same and under this arrangement it is correct and is a case where the Pressure-Decline Method works perfectly.

Chart 2. Now we refer to Chart 2 in which we have different sized containers A with 30,000 CF, B with 20,000 CF; and C with 10,000 CF, making a total of 60,000 CF the same as we had on Chart 1. We have the same original pressure of 400# and all valves are closed.

Example #5. Suppose we open valves A, B, and C, then open valve D long enough to produce 15,000 CF of gas through the meter so that 7,500 CF goes out of A, 5,000 CF goes out of B, and 2,500 CF goes out of C. Since 7,500 CF is ¼th of the 30,000 CF content of A then its pressure loss is ¼th of 400#, or 100# leaving 300# pressure in A. Since

5,000 is ¼th of the 20,000 originally in B likewise it loses 100# leaving 300#.

Also since 2,500 is ¼th of the 10,000 originally in C then its loss is 100# leaving 300#. Averaging, we find, A with 300#, B with 300# and C with 300# making a total of 900# and dividing by 3 shows 300# weighted average pressure, or a loss of 100#. With a production of 15,000 CF we find the rate of 150 CF per pound drop and multiplying by 400# shows original content to be 60,000 CF which is correct. The reason it is correct is that the pressures in all three varying sized containers have gone down uniformly. In other words, the pressure was the same in each container.

Example #6. Now to show how with Boyle's Law still acting as it should the Pressure-Decline Method can become inaccurate. Suppose we start in all over with the containers filled and 400# and all valves shut We now open valve A and then open valve D long enough to allow 15,000 CF to be produced through meter X, obviously it all comes from container A, leaving just half of its original content and of course half its original pressure, or 200#.

Now let us add to see what the weighted average pressure is, A with 200#, B with 400#, and C with 400# totaling 1,000# divided by 3 gives 333-1/3# weighted average pressure. Subtracting from 400# shows a weighted average pressure drop of 66-2/3# while 15,000 CF were being produced at a rate of 225 CF per pound drop, and multiplying by 400# gives 90,000 CF as original content which we know to be wrong since we started out with the set amount of 60,000 CF.

The thing which got us into trouble here is that we weighted each container in order to get a weighted average pressure without taking into account that the containers are different in size. What we really need to know is the equilibrium pressure which would result if all the containers were allowed to equalize, that is, if we insist on using some weighted average pressure knowing that the containers differ in size and if we do not know how they differ. In other words, we arrived at an average weighted pressure by considering area rather than volume. Accord-

ing to Boyle's Law pressure varies with volume and not with area unless each area happens to contain the same volume."

Q. Right in that connection, Mr. Hughes, in averaging pressures in the field such as Mr. Hammer averaged them and such as the Railroad Commission of Texas averaged them, you are as a matter of fact weighting your pressures against areas, are you not?

A. Yes, that is right.

Q. And is it true or not that different areas in the Panhandle field vary widely with respect to gas content?

A. Yes, it is true that the content does vary widely.

Q. You may proceed.

A. "Example #7. But coming back to show why 333-1/3# although it is a weighted average pressure based merely on numbers of containers (each containing the same surface area) is not the same as the equilibrium pressure which we want, suppose at the end of Example #6 we let valve A open (D of course still remains closed) then we open valves B and C. Gas will move from containers B and C into container A. However, now gas will be produced into meter X since valve D remains closed. Container B will furnish 5,000 CF and container C will furnish 2,500 CF making a total of 7,500 which will migrate into A. After B has furnished 5,000 it will have 300# pressure instead of 400#. After C has furnished 2,500 it will have 300# pressure instead of 400# and then when A has received the combined amount of 7,500 it will have 300# instead of 200#. In other words the whole system will have become equalized at 300# which is also the arithmetic weighted average pressure after equalization. We have seen that the system has not been allowed to produce any gas yet its new weighted average pressure is 300# instead of the 333-1/3# weighted averaged at the beginning of the period of equalization. Thus without any production the weighted average pressure has declined 33-1/3#. This decline leads to an absurdity, where with no production the pressure loss is 33-1/3#, the rate becomes zero per pound drop and multiplying by 400# we find zero as the original content.

Example #8. Suppose we start again where Example 6 ended, with a total production of 15,000 having been taken

out of A, with B and C still untouched, we found that gave 66-2/3# drop or 225 CF per pound drop, and indicated an original content of 90,000.

From that given situation let us produce enough from each container to result in a 100# drop in each, from where they were at the end of Example 6.

In order to do this A would be permitted to produce 7,500 out through the meter and in doing this its pressure would drop 200# to 100#. B would be permitted to produce 5,000 out through the meter and in doing this its pressure would drop from 400# to 300#. C would be permitted to produce 2,500 through the meter and while doing it its pressure would drop from 400# to 300#. The total amount produced from the entire system during this procedure would be 15,000 CF. The remaining weighted average pressure would be found by adding A with 100#, B with 300#, and C with 300#, totaling 700# and dividing by 3 gives 233-1/3#.

Subtracting this from 333-1/3# leaves 100# as the weighted average pressure loss. With 15,000 CF produced during this loss the rate is 150 CF per pound drop instead of 225 CF per pound drop in Example 6. Since each container lost the same number of pounds during example 8 the result of that calculation came out correct, namely 150 CF per pound drop, and multiplying by 400# indicates 60,000 CF original content, which we know to be correct, instead of the wrong figure of 90,000 found in Example 6. In other words the pressure drop in each container was identical

Example #9. At this point it is important to show that, while we obtained the correct figure from a study of the interval in Example 8, we would still have an erroneous result if, instead of using that interval alone, we would have gone back and computed by the overall method from the beginning.

The overall method would combine the results of Examples 6 and 8, namely, container A had produced 22,500 CF with a remaining pressure of 100#; B had produced 5,000 CF with a remaining pressure of 300# and C had produced 2,500 CF with a remaining pressure of 300#. Thus we had a grand total production of 30,000. We now add the pres-

sures, A with 100#, B with 300#, and C with 300#, totaling 700# and dividing by 3 find the weighted average pressure to be 233-1/3# (identical with that found previously as at the end of Example 8).

The total loss in pounds from 400# is 166-3/3# and with a production of 30,000 we find we had produced 180 CF per pound loss. We observed in Example 8 that the correct production should be 150 CF per pound drop and that it was indicated by using merely one interval during which each container lost the same number of pounds pressure. Therefore, to go back and average in everything from the beginning does not increase the probability of accuracy, in fact this proves definitely that it has lead away from a correct figure to an erroneous one. But referring to the 180 CF indicated production per pound drop and multiplying by 400# we find at the end of Example 9 the indicated original content of 72,000 CF.

Here we see the effect of early production coming from the richest container leading to an erroneously high figure of original content being 90,000 instead of the known correct figure of 60,000. During the next stage of production some was taken from leaner containers and by the overall method the computed original content has dropped from 90,000 to 72,000 but still not know the correct figure of 60,000.

Conclusions From the 'Text Book' Examples.

1. If the pressure-decline method is working correctly it shows a constant amount of gas produced per pound pressure drop, whether computed on any one of several intervals or by going back to the beginning each time.

This is accomplished when each container is equal in size (Chart 1) whether the pressures in each are going down *uniformly* (Example 1), or going down in varying amounts (Example 2).

It is accomplished with containers of unequal size (Chart 2) only when the pressures in each are going down uniformly (Example 5) or when for a given interval the pressure loss in each container is the same (Example 8).

2. If the pressure-decline method is not showing a con-

stant rate of production per pound drop in pressure then it is due to the fact that we are having unequal pressure drops in containers having unequal content (Chart 2). This is shown by Examples 6, 7 and 9.

3. It further shows that, if that rate of production per pound pressure loss is declining with successive periods, then the early production was coming from larger containers than those furnishing the later production, or at least it shows that some production was beginning to come from smaller containers. This is shown by Examples 6 and 9.

Chart 1 has heretofore been marked as Exhibit 188 and Chart 2 as Exhibit 189 and referred to as such during the cross examination of Federal Power Commission witness Hammer.

The pressure decline method as applied by Mr. Hammer cannot give the correct answer because pressures are not equal in the Panhandle of Texas gas fields and for the further reason that the volumes are not equal in the various areas of the field. Mr. Hammer has attempted to secure a weighted pressure in the field by taking the area of each segment between isobar lines and multiplying this by the pressure obtaining in each segment as to each quadrant and then dividing each quadrant total by the number of acres in the quadrant.

This method necessarily assumes that each segment as outlined by the isobar lines in any given quadrant contains the same volume of gas per acre as every other segment in the quadrant. This obviously is a false assumption. Mr. Hammer therefore has weighted his pressures against areas and not against volumes.

The grouping of quadrants as illustrated by Federal Power Commission Exhibit No. 180 could not possibly correct this error for the reason that in each of the quadrants the volume varies over the areal extent of the quadrant. In other words, he does not have uniform volumes per acre for each quadrant and neither does he have uniform pressures for each quadrant. This being true he could not possibly

arrive at the correct estimate of reserves of gas in place by the application of the pressure decline method as he applied it.

[Exhibit 188, Chart, appears at page 3883.]

[Exhibit 189, Chart appears at page 3887.]

The Pressure-Decline Method in the Texas Panhandle Gas Field.

Based upon a strict assumption that the Panhandle Reservoir is 100 per cent volumetric control, a critical examination has been made of the Pressure-Decline Method.

The pressure figures used in the computations are the weighted averages found by the Texas Railroad Commission. The first field-wide survey was conducted by the Commission in the summer of 1935. A second one was made in January 1936 and due to winter operating conditions it was considered less accurate and involved unnecessary inconveniences and therefore the winter survey was discontinued in favor of an annual one in the summer.

During the contouring of the 1940 pressure map this fall by the Railroad Commission, an error was discovered in the 1939 map. The error affected some 30 sections of land in southeast Gray County where the pressures on the 1940 map are necessarily raised over what they were on the 1939 map. It is due to new control shown by the Lone Star Fowler wells in Section 118 Block H&GN. The wells which gave the new control for the 1940 map had a drop in pressures during the years as follows:

Lone Star Fowler #1 8-1-39 pressure 323#. 8-1-40 pressure 304#:

Lone Star Fowler #2 8-1-39 pressure 322#. 8-1-40 pressure 303#.

The pressure drop in each was 19 pounds.

I presume it was an oversight that those pressures were not used on the 1939 map. At any rate this shows that the weighted average pressure for 1939 was wrong. Had the

pressures in these wells being used the weighted average would have been some higher than was found and reported by the Commission. This would have caused a smaller drop in the weighted average pressure from 8-1-38 to 8-1-39 and consequently a larger drop between 8-1-39 and 8-1-40 than exists in the published figures.

Therefore for lack of a correct figure for 1939, or rather due to the known fact that the 1939 figure is in error, I am ignoring it and in the following study am treating the two-year period 8-1-38 to 8-1-40 as a unit whose production resulted in the pressures accepted as being correct at the date 8-1-40.

Chart "A".

If the Pressure-Decline method were working correctly, the production per pound drop in pressure would be constant, that is, at any given pressure survey date the cumulative production divided by the overall pressure loss would give a constant figure.

Date	Cumulative Production Mcf.	Pressure Loss From 430#	Production Mcf. per Pound Drop
8-1-35	5,197,693,413	67.49#	77,014,270
7-1-36	5,754,179,067	75.00	76,722,387
7-1-37	6,307,060,469	82.95	76,034,484
8-1-38	6,929,985,630	92.34	75,048,577
8-1-40	8,082,404,377	111.69	72,364,620

The fact that the production per pound drop is not constant proves conclusively that the pressure-decline method is not working correctly in the Texas Panhandle.

The downward trend in the rate of production per pound drop is shown graphically on the accompanying Chart "A". If the pressure-decline method were working correctly that downward trending curve would be a horizontal straight line.

Chart "B".

If the pressure-decline method were working correctly, the rate of production per pound drop computed by the overall method at any given pressure survey date could be multiplied by the total number of pounds original pressure

and obtain a constant figure indicating the total original Reserve.

Date	Rate of Production in MCF per Pound Drop Overall Method	Orignal Reserve MCF Obtained by Multiplying Rate per pound by 430#
8-1-35	77,014,270	33,116,136,100
7-1-36	76,722,387	32,990,626,410
7-1-37	76,034,484	32,694,828,120
8-1-38	75,048,577	32,270,888,110
8-1-40	72,364,620	31,116,786,600

The figures indicating original reserve are not constant and this fact proves conclusively that the pressure-decline method is not working correctly in the Texas Panhandle; the importance and significance of the downward trend in the computed original reserve is shown on Chart "B".

If the method were working correctly that downward trending curve would be a horizontal straight line until it finally intersected an extension of the 45 degree sloping line.

Chart "C".

If the pressure-decline method were working correctly, the rate of gas produced per pound pressure drop would be the same for any or all intervals or periods between pressure surveys, that is, the rate "currently" would be constant.

Period	Production During Period MCF	Pressure Loss During Period	Production Mcf. per pound loss during period or "currently"
Beginning to 8-1-35	5,197,693,413	67.49#	77,014,270
8-1-35 to 7-1-36	556,485,654	7.51	74,099,288
7-1-36 to 7-1-37	552,881,402	7.95	69,544,830
7-1-37 to 8-1-38	622,925,161	9.39	66,339,208
8-1-38 to 8-1-40	1,152,418,747	19.35	59,556,524

The current production per pound drop is not constant and this shows conclusively that the pressure-decline method is not working correctly in the Texas Panhandle. This rapidly declining rate of production per pound loss is shown plotted against accumulated production on Chart "C".

If the pressure-decline method were working correctly this would be a horizontal straight line.

The importance of this curve is discussed at length toward the end of this report.

My observation for several years has been that the production in the early life of the field came from richer than average areas and the pressure loss at that time was in those areas and hence an application of the pressure-decline method would give an estimate of original reserve that is too high.

I have maintained that the remaining high pressure areas were lean and when they finally came into depletion their pressures would drop faster with a continually lowering of the estimate of original reserve by the pressure-decline method.

There are still large areas of high pressure lean acreage which can cause this decline in rate of production per pound drop to continue into the future.

Our reservoir is not a perfect container and migration is restricted in some areas. Unequal withdrawals have caused unequal pressure declines in various parts of the field. I believe the declines as a whole have been in richer than average areas and if the entire field were shut in today until the pressures became equalized, the final pressure would be less in pounds than our present so-called weighted average pressure. Theoretically it is this equilibrium pressure that is needed (and which we do not have) in order to apply Boyle's Law correctly to the container.

In opposition to this, it has been pointed out by some who are trying to use the pressure-decline method in the Panhandle that even though the original content of gas did vary in the field, still the variation would average out in all pressure bands. That is, within each pressure band at any date they are so widespread and include all kinds of acreage good bad and average, that any given band is typical of the field.

Now, if by chance this does happen to be true, then the situation is more serious than I have suspected.

For if this be true, then the pressure-decline method should be working perfectly, giving constant results.

Obviously it is not working out that way and in order to explain why it isn't we must admit some situation to exist in the reservoir which is causing an ever lessening amount of production per pound drop.

This decline in the amount of production per pound drop has been going on throughout the entire period in which we have the official pressure surveys, from August 1935 to the present, August 1940. This is the period in the history of the field in which we have the best information, both as to pressures and production.

It appears logical to project into the future this changing rate of production per pound drop.

This would be done by extending the five year control curve on Chart "C" as a downward trending straight line.

The extension would intersect the base line at about 18 trillion cumulative production which at first thought might be interpreted as the indicated original reserve.

However, if these declining rates of production per pound drop be actually set up in table form and the necessary drop in pressure required during a given amount of production is computed it will be found that the field is at zero pressure when the cumulative production is about 16.3 trillion.

Summary.

1. It is apparent that the pressure-decline method is not working correctly in the Texas Panhandle. This is not subject to argument. I recognize Boyle's Law and I have not upset any law in physics in proving that the method is not working correctly, in fact I have used Boyle's Law to prove my conclusions.

2. I have shown a valid reason why the pressure-decline method is not working correctly, and if my reason is sound, conditions still exist which will cause the downward trend in production per pound drop to continue into the future.

Such a continuation points to an estimate of original reserve of 16.3 trillion cubic feet of gas.

This critical study of the pressure-decline method re-

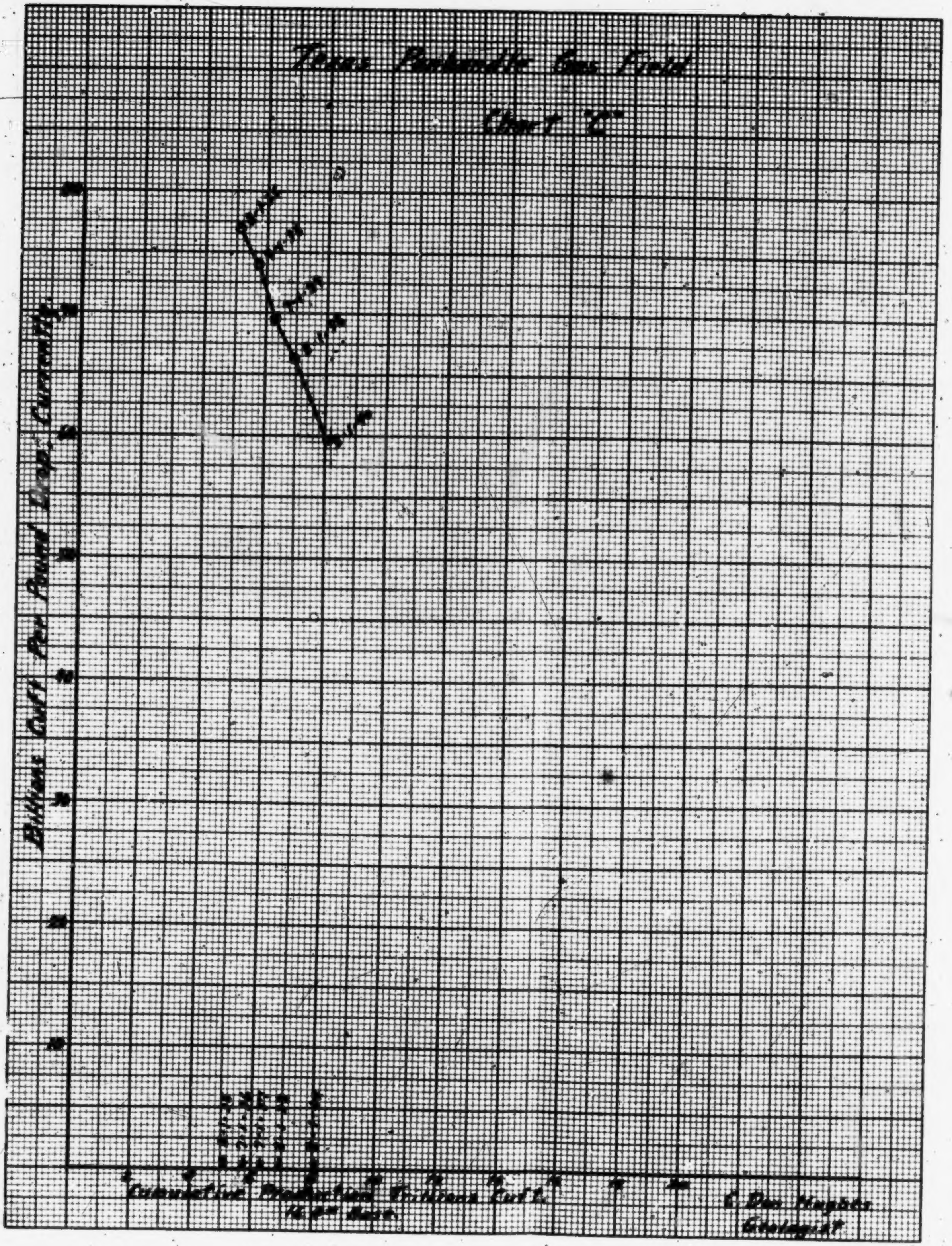
veals a steady decline in the rate of production per pound drop.

While it shows positively that the orthodox manner of using the method cannot be relied upon, since it gives a different answer each time, still it is believed that the definite rate of change in the production per pound drop is significant.

Therefore, this study shows that the method does not give a reliable answer at any one date, but that it becomes a guide for the future by extending the changing rate of production in accordance with actual performance during the past five years.

An extension of this trend points to an original reserve of 16.3 trillion for the field. If this is correct, then my estimate of approximately 19¼ trillion is too high. Even though this is the indication, I am inclined to stand on the evidence that 19¼ is a reasonable figure and that the manner in which I arrived at it is reasonable. However, in the light of contemporary trends in the downward rate of production per pound drop in the reservoir it may be that a new angle has developed, the effect of which should be incorporated in a revision downward of my 90 per cent recovery factor.

Exhibit No. 258



Pressure Decline Method.

Using Mr. Hammer's Quoted Production Prior to 8-1-35, his production figures from 8-1-35 to 8-1-39 and weighted average pressures for the field at the two dates computed from Mr. Hammer's working papers.

By using data in Mr. Hammer's working papers I have computed the weighted average pressures for the Panhandle field, including Wheeler County Quadrant I, at 8-1-35 and found it to be 369.10 pounds, or a drop of 60.90 pounds from original 430 pound pressure.

Using this data, I also computed it for 8-1-39 as 331.73#, including Wheeler County Quadrant I, or a drop of 98.27 pounds from original pressure of 430 pounds.

Mr. Hammer has entered a figure of 4,833,608,743 Mcf. quoted by him as being the cumulative production for the field prior to 8-1-35 arrived at by the Phillips Petroleum Company.

He showed as his own metered production for the period 8-1-35 to 8-1-39 from records of the Texas Railroad Commission 2,430,370,036 Mcf.

I have made a study of this basic data in order to see what he would have arrived at, in comparison with my results, had he applied the pressure decline method in the orthodox manner, that is, treating the field as a whole and computing the production per pound drop in pressure.

In order that these results could be compared with my results I have converted his 14.65 pound pressure figures to 16.4 pound base.

Multiplying 4,833,608,743 Mcf. by .892329 gives 4,317,814,354 Mcf. 16.4# base.

Multiplying 2,430,370,036 Mcf. by .89329 gives 2,171,025,249 Mcf. 16.4# base.

Using the pressure-decline method, the production at 8-1-35 of 4,317,814,354 Mcf. was divided by the pressure loss at 8-1-35 or 60.90 pounds, indicating a production per pound drop of 70,900,071 Mcf. This rate of production per

pound loss was multiplied by 430 pound original pressure resulting in 30,487,030,530 Mcf. as an estimate of original reserves down to zero wellhead.

Now to test the reliability of the method we add the production for the 4-year period (8-1-35 to 8-1-39) to the production prior to 8-1-35, or 2,171,025,249 Mcf. plus 4,317,814,354 Mcf. and get a cumulative production of 6,488,839,603 Mcf. for the entire period prior to 8-1-39. Dividing that by the total pressure loss of 98.27 pounds at 8-1-39 we find a production of 66,030,728 Mcf. per pound loss which is much less than we found before and which shows that the pressure-decline method is not working correctly. We should have obtained a figure approximately the same as we had for the first period. Multiplying this lesser amount of production per pound loss by 430 pounds we get an estimate of original reserves of 28,393,213,040 Mcf., further showing that the method is not giving a consistent estimate.

In order to visualize this changed estimate the information has been plotted on charts which also show the answers I arrived at when I used our production data and the weighted average pressures for the field as found by the Texas Railroad Commission.

On Chart "A"1 I have plotted with small triangles, as the indicated control points, the results obtained using Mr. Hammer's data showing definitely the lessened rate of production per pound loss along with his cumulative production for the field. It can be readily seen that his own production and pressure figures show a faster changing rate than the one we have with our figures.

On Chart "B"1 I have, with similar symbols, plotted the resulting estimates of original reserves arrived at with his figures as compared with those arrived at with ours. Again it is noticeable that as plotted against cumulative production on the horizontal scale the indicated original reserve figure had dropped more rapidly than our figures had.

It is quite evident on Chart "B"1 that if the rate of change based on his data continues, then I have overestimated the reserves when I show 19¼ trillion.

Now we will test the performance of the field on what Mr. Hammer states is the only accurate history we have, that is, his 4-year period, 8-1-35 to 8-1-39.

His production of 2,171,025,249 Mcf. is divided by his pressure loss for the period (369.10# — 331.73# = 37.37#) of 37.37 pounds showing a production per pound loss of 58,-095,404 Mcf., which is surprisingly low compared with the 70,900,071 Mcf. per pound loss shown by his data for the period prior to 8-1-35.

Multiplying the production per pound loss for the 4-year period by 430 pounds, we find an estimated original reserve of 24,981,023,720 Mcf., which again is quite in contrast with the 30,487,030,530 Mcf. arrived at, using the period prior to 8-1-35.

In order to visualize these data I have plotted the changed rate of "contemporary" or "current" production on Chart "C" 1 where it can be seen not only in its own light but in comparison with a similar downward trending rate shown by our figures.

This evidence on Chart "C" 1 is very significant. It shows both with his data and our data that the production per pound pressure loss is declining very rapidly.

If this rate exhibited by Mr. Hammer's data is extended as a straight line and if increments of production identical with this 4-year period are added to the cumulative production then it is possible to read from the extended line the rate of production per pound drop which might be expected. By dividing this rate into the increment of production, the number of pounds pressure loss can be computed for each increment. By subtracting this pressure drop from the pressure at the beginning of the increment then the remaining pressure can be computed.

This has actually been done and it shows that the pressure of the field is exhausted when the cumulative production is approximately 14.3 trillion cubic feet. The number of increments necessary to bring that about is approximately 3½ and if those increments of production are assumed to take place during four years each, as his actually did, then the computed years involved would be approximately 14 years after 8-1-39.

Another phase of the study consists of using annual production for the field totaled from Mr. Hammer's working

papers and annual weighted average pressure drops computed from his working papers. The production was converted from 14.65# base to 16.4# base using the factor .89329.

Period	Production Mcf. 14.65# base	Production Mcf. 16.4# base
8-1-35 to 8-1-36	620,404,940	554,201,528
8-1-36 to 8-1-37	595,387,041	531,853,290
8-1-37 to 8-1-38	616,439,219	550,658,990
7-1-38 to 8-1-39	598,138,836	534,311,441
	2,430,370,036	2,171,025,249

The pressure drop for each period was found by subtracting the weighted average pressures at the end of each from that at the beginning of each period.

Period	Weighted Average Pressure	Pressure Drop
8-1-35	369.10#	
8-1-35 to 8-1 36	359.86	9.24#
8-1-36 to 8-1 37	350.95	8.91
8-1-37 to 8-1-38	341.87	9.08
8-1-38 to 8-1-39	331.73	10.14

The production for each period was divided by the pressure drop to determine the rate of production per pound drop.

Period	Production MCF 16.4# Base	Pressure Drop	Production Per Pound Drop MCF 16.4#. Base
8-1-35 to 8-1-36	554,201,528	9.24	59,978,520
8-1-36 to 8-1-37	531,853,290	8.91	59,691,727
8-1-37 to 8-1-38	550,658,990	9.08	60,645,263
8-1-38 to 8-1-39	534,311,441	10.14	52,693,436

The rate of production per pound drop was steady during the first three periods but dropped sharply during the last period, this may be visualized on Chart "C" 1 where it has been plotted as a curve controlled by small squares at each point.

This information was plotted against cumulative production from 8-1-35 on the horizontal scale.

It is readily seen that the net effect of these annual rates of production per pound drop shows a decided decline at the end of the priod, an average curve through these four points would slope downward nearly parallel with the other two curves on Chart "C" 1. This confirms the slopes of the other two.

The cumulative figures from 8-1-35 for use on the horizontal scale follow:

Period	Production for Period MCF 16.4# Base	Cumulative from 8-1-35, MCF 16.4# Base
8-1-35 to 8-1-36	554,201,528	554,201,528
8-1-36 to 8-1-37	531,853,290	1,086,054,818
8-1-37 to 8-1-38	550,658,990	1,636,713,808
8-1-38 to 8-1-39	534,311,441	2,171,025,249

The rate of production per pound drop annually may be multiplied by 430 pounds giving an estimate of original reserves for the field:

Period	Production Per Pound Drop MCF 16.4# Base	Original Reserves To 0# Gauge MCF 16.4# Gauge
8-1-35 to 8-1-36	59,978,520	25,790,763,600
8-1-36 to 8-1-37	59,691,727	25,667,442,610
8-1-37 to 8-1-38	60,645,263	26,077,463,090
8-1-38 to 8-1-39	52,693,436	22,658,177,480

Referring again to the declining rate of production per pound pressure loss as plotted on Chart "C" 1 with the small squares as the control points the trend has been extended into a sloping straight line.

If this declining rate of production continues in accord with the extended curve then the following will be the result.

When the cumulative production on the horizontal line has reached 3 trillion the rate of production for the increment of production of 828,974,751 Mcf. which brings the cumulative total to 3 trillion will be about 47.5 billion per pound. Dividing this into the production increment shows that a 17.45# drop will be necessary. If we subtract this

from the existing pressure at 8-1-39 it leaves 314.28 as the remaining pressure.

By continuing this procedure in increments of 1 trillion each it is found that the pressure will be exhausted when the cumulative production is slightly over 9 trillion. If we subtract the approximately 2 trillion, cumulative production at 8-1-39 it leaves 7 trillion.

Mr. Hammer shows the total production for the 4-year period as 2,171,025,249 (16.4# base) or an average of approximately 543 billion per year.

Dividing the remaining 7 trillion at 8-1-39 by 543 billion shows approximately 13 years indicated to take the field down to zero pressure wellhead."

Q. I have just a few questions. Mr. Hughes, if you wil refer to your Chart "C" 1 that follows Page 24 of your Exhibit 258. You have shown three curves there. The furthest curve to the right is based upon the Railroad Commission's figures, is it not, for those respective years as indicated upon the curve?

A. Yes, that is right.

Q. The middle curve is based upon Mr. Hammer's figures for the period August 1, 1935 to August 1, 1939, but is not broken down into years?

A. That and the period prior to 1935. That curve is based upon—

Q. That curve to the left shows Mr. Hammer's figures year by year, doesn't it?

A. That is right.

Q. If you extend that curve as you have stated through the year 1939, we will say, and through the circle representing 1937 and approximately half-way—we should say between the circles representing 1938 and the circle representing 1936—you get the curve that is projected as you have shown it?

A. That is right.

Q. Now, Mr. Hammer's curve on his figures show a slight increase in production per pound drop for the period from August 1, 1937 to August 1, 1938?

A. That is right.

Q. Could that be accounted for by Mr. Hammer's failure

to take into account quantities of gas that have been produced and not metered?

A. Yes, assuming that his contouring of the maps of those different dates and planimetering and all might not account for some of that variation.

Q. Could—there could very easily be mistakes made in matters of that kind no matter how careful you were?

A. That is right.

Q. That slight increase is not shown on the Railroad Commission's figures on the curve to the right?

A. ~~No.~~

Q. The curve farther to the right on that chart?

A. No.

Q. Now, just one or two more questions.

Will you go back to Chart A on Page 14. Now you show production in Mcf. per pound drop in pressure covering the entire field in the table on Page 14, do you not?

A. That's right.

Q. That's right. It starts out at 8-1-35, 77 billion per pound drop in pressure—77 billion cubic feet—that's right—and taking 1-19-40, it has dropped to a little more than 72 billion per pound drop in pressure.

A. That is right.

Q. But now those are cumulative figures, are they not?

A. Yes.

Q. That's right. When you get your 77 billion at 8-1-35 you have taken all production from the beginning of the field up to that time, is that correct?

A. Yes.

Q. And when you get your 76 plus billion per pound production in 1936 you have taken the entire history of the field up to that time?

A. Yes.

Q. And likewise you have taken everything back of each year and brought it up to the year which you have shown here, is that correct?

A. Yes, that is right.

Q. Now, if you had broken that down into years you would have gotten a much greater decline in your rate of production per pound drop, wouldn't you?

A. Yes.

Q. Now, that is shown on Chart "C", that is, I mean on Page 16, your table set out on Page 16, which discusses Chart "C".

A. That's right.

Q. Now, you will notice there at 8-1-35 you have 77 billion plus cubic feet per pound drop which is the same figure which you had on the chart on Page 14, isn't it?

A. That's right.

Q. When you divide that up into years, get the per-pound drop for each year for the period of 8-1-38 to 8-1-40, instead of the 72 billion plus, which you show on Page 14 and which is cumulative for those two years, you get 59 billion plus, is that not correct?

A. That is right.

Q. Showing that each year as you go forward, no matter where you start, you get less production the following year than you did the preceding year per pound drop in pressure, is that correct?

A. That is correct.

Mr. Keffer: I merely wanted to explain, Mr. Examiner, the difference between the cumulative figures and the figures from year to year. I wasn't sure that it was as clear as it might be.

Q. Now, on that same basis, referring to Page 15, you show there, using the pressure decline method, the different answers that you would get if you would make reserve estimates at different periods, do you not?

A. That's right.

Q. And it goes from 33 trillion plus to 31 trillion plus?

A. Yes.

Q. But those are again cumulative, aren't they?

A. That's right.

Q. That's right, when you make the estimate on this basis at 8-1-40, you have taken everything back of 8-1-40 to the beginning, is that correct?

A. That's right.

Q. Now, when that is broken down again into years—well, I don't see where you have made an estimate on that, but go back to Page 16. If you were to make an estimate for the 2-year period, 8-1-38 to 8-1-40, in which you have a little less than 60 billion production per pound drop in

pressure, your estimate, instead of being 31 trillion, plus, as shown on 15, would be something in excess of 25 trillion, wouldn't it?

A. Yes, it would be.

Q. Just roughly?

A. It would be 430 pounds times this.

Q. 59 plus?

Mr. March: 59 plus, billion?

Mr. Keffer: That's right.

The Witness: That's right.

By Mr. Keffer:

Q. Now, those same general observations I think would apply to Mr. Hammer's figures which you also show on your subsequent charts, in your exhibit, but I want to call attention to just one thing.

If Mr. Hammer had made his estimate based upon production and decline in pressure for the period 8-1-38 to 8-1-39, he would have had, as shown by Page 26, a pressure drop of 10.14 pounds, wouldn't he?

A. Yes.

Q. On Page 27 he shows production of 534 billion plus, or a production of 52 billion plus per pound drop in pressure.

A. That is right.

Q. That is on 16.4 base?

A. Yes.

Q. Now, if he had made his estimate for that period, you would have the figure as shown on the second table on Page 28 which is 22 billion—I mean 22 trillion—658 billion original reserve on a 16.4 base?

A. That is right.

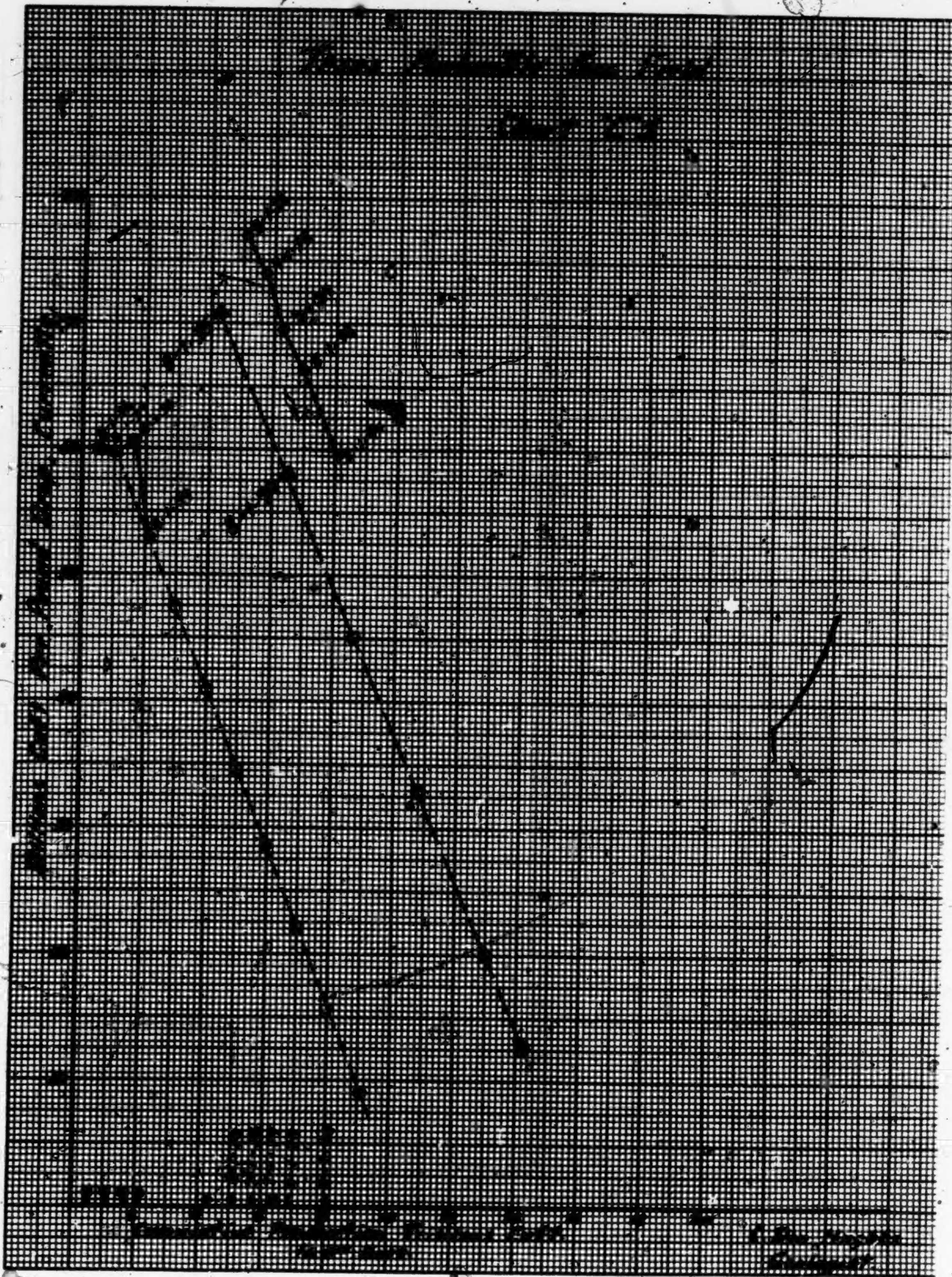
Q. That is the figure that he would get if he had used the last available data for a complete year?

A. That is right.

* * * * *

4515
Exhibit No. 258

Exhibit 258.



Hughes made a further study of Hammer's estimate of reserves with particular reference to the utilization of quadrants by Hammer. This study is contained in Exhibit 264 and the testimony in connection therewith in Volume XCIV, pages 14462 to 14476.

Exhibit 264 contains tables A and B which are based upon the working papers of Hammer.

There is also attached to the Exhibit two maps which are exact duplicates of Hammer's isobar map, Exhibit 179. The first of these maps shows the various counties of the field colored in red and in green. The counties colored green are the counties which have gained gas by migration as reflected by Hammer's data. The counties colored in red indicate the counties that have lost gas by migration, as indicated by Hammer's data. The second map follows the same color scheme as to quadrants and shows the quadrants as outlined on Hammer's isobar map, Exhibit 179, which have gained gas by migration, colored green, and those which have lost gas by migration, colored red, all as disclosed by Hammer's data.

The Exhibit itself contains a detailed explanation of the various figures set out in Tables A and B.

The calculations made by Hughes show, according to Hammer's data, that Wheeler County has lost in excess of 48 billion cubic feet of gas by underground migration during the four-year period covered by Hammer's data. The only place that this gas could have drained to would be Gray County since there are no other counties in the field adjoining Wheeler County. The gas, therefore, would have migrated from a lower pressure area to a higher pressure area as shown by the isobar configurations on Hammer's Exhibit 179. (Vol. XCIV, pp. 14464-14465.)

Gray County lost almost 14 billion cubic feet of gas by migration, and this, plus the 48 billion which it gained from Wheeler County, makes a total of 62 billion cubic feet that migrated out of Gray County. The only possible place for this gas to go would be Carson County to the west. Hammer's map, Exhibit 179, shows the pressures to be higher in Carson County than in Gray County. There

fore, this volume of gas necessarily migrated from a low pressure area to a higher pressure area. (Vol. XCIV, p. 14465, 14466.)

Carson County lost almost 163 billion cubic feet of gas during the four-year period. It had gained 62 billion cubic feet from Gray County which made a total of approximately 225 billion cubic feet that migrated out of Carson County. Some of this gas could very logically have gone into Hutchinson County, but not all of it, since Hutchinson County gained approximately 134 billion cubic feet. This left approximately 91 billion cubic feet that Hutchinson County might have received from Carson County, which necessarily migrated to some other county. (Vol. XCIV, pp. 14467-14468.) This gas could not go to Potter County since Potter County also lost 27 billion cubic feet approximately. The only place it could go would be Moore County. There migrated into Moore County, therefore, the approximate 91 billion cubic feet left out of the gas Hutchinson County received from Carson County, plus the 27 billion cubic feet that migrated out of Potter County into Moore County. It is evident, therefore, that Moore County received approximately 118 billion cubic feet of gas by migration from Hutchinson and Potter counties. Moore County, as shown by Hammer's map, Exhibit 179, has a higher pressure than Hutchinson County. (Vol. XCIV, pp. 14467, 14468.)

All of the above calculations are shown in tabulated form on page 5 of Exhibit 264. Hughes stated that, assuming Hammer's data were correct, it actually showed that substantial volumes of gas had migrated from Wheeler County to Moore County. (Vol. XCIV, pp. 14468, 14469.) Hughes stated, however, that he did not mean to imply that gas had actually migrated from Wheeler County to Moore County, or that gas migrated from low pressure areas to high pressure areas, which is indicated by a study of Hammer's data. He explained the absurd situation which results from a consideration of Hammer's data by the fact that Hammer's estimates of gas in the various quadrants of the field are erroneous. It is Hughes' opinion that the weighting and averaging process used by Hammer had the effect to aggravate or overestimate the gas actually

in place in many of the quadrants of the field. It is the witnesses' opinion, however, that the study does show that Hammer's estimate of reserves for the various quadrants and for the field as a whole based upon this method, is entirely erroneous (Exhibit 264, page 5 to 8.)

Hughes testified that there is no drainage in or out of the Texas Panhandle Field as a whole and that Hammer could have applied his data to the field as a whole without dividing the field into quadrants. If he had treated the field as a whole and disregarded quadrants then Hammer's data would have resulted in an estimate of approximately 28 trillion cubic feet to zero pounds wellhead on a 14.65 pound pressure base, but that the method of estimating reserves for each quadrant, and then adding these various estimates to determine the estimate for the field resulted, on Hammer's data, in an estimate of approximately 31 trillion cubic feet. Hughes does not agree that the 28 trillion cubic feet is the correct estimate, but merely states that by using the same data Hammer increased his estimate by approximately 3 trillion cubic feet by the division of the field into quadrants. (Vol. XCIV, pp. 14474-14475.)

Cross Examination on Exhibit 258.

On cross examination Hughes again reiterated that the pressure-decline method as applied to the Texas Panhandle Field would give approximately the correct result if there were any method whereby the correct weighted average pressures could be obtained. The correct weighted average pressures cannot be obtained by weighting on acreage alone; in order to get the correct weighted average pressure it should be weighted on volume, not on acreage. (Vol. XCIV, p. 14503.)

Hughes again explained the error that was made by the Railroad Commission in contouring its 1939 pressure map and stated that this error was called to his attention by the Railroad Commission staff. He stated further that if he had used the 1939 pressure figure that the curve which is shown on Chart C, Exhibit 258, would have declined much more from 1938 to 1939 than it did for the period from 1938 to 1940. (Vol. XC, pp. 13810-13822.) Hughes did not attempt to correct the error because this

could only have been done by recontouring the entire field which he did not do. (Vol. XC, p. 13823.) Although the wells upon which the error was made were located on the east field, it affected the weighted average pressure on the entire field. (Vol. XC, p. 13826.)

The witness stated that he had been applying the pressure-decline method to the Texas Panhandle Field since the Railroad Commission had been putting out weighted average pressures, but it did not give consistent results; that he would not shut his eyes to the definite trend which the pressure-decline method showed and that if this trend continued in the future as it had in the past five years that this method would point to an original reserve in place of 16.3 trillion cubic feet. (Vol. XC, pp. 13842-13844.)

It is the witness' opinion that if the field were shut in and pressures were permitted to equalize that the equalized pressure would be less than the Railroad Commission's weighted average pressure and less than Hammer's weighted average pressure, and that one reason that this would be true is the fact that the high pressures now obtaining in the field are located for the most part in the lean areas; that is, areas that have less than the average volume of gas in place; (Vol. XCI, pp. 13881-13883) and that the difference in the so-called weighted average pressure and the equilibrium pressure would probably be quite a sizable difference. (Vol. XCI, p. 13884.)

The witness was referred to Chart C-1, which contained a graph based upon Hammer's pressure and production figures. He stated that the decline from 1938 to 1939 was not unusual because it corresponds with other data with which he has compared it. He thinks it is more likely that the pressure declines with respect to production in some of the earlier years covered by Hammer's study are more likely to be unusual. (Vol. XCI, pp. 13901-13904.) He made a reasonable interpretation of the data shown on Chart C-1 in drawing his curve based upon such data. Upon being accused of ignoring both the 1936 and the 1938 points he replied that he had not ignored either but that he gave due weight to both his line as drawn inter-

sects both the 1939 and 1937 points, and just about splits the difference between the 1936 and 1938 points, and that however interpreted, the data as taken from Hammer's calculations show a decided downward trend, whereas, if the pressure-decline method were giving the correct results the data would show a straight horizontal line instead of the sharply downward trending line. (Vol. XCI, pp. 13905-13907.)

The witness also reiterated that if the application of the pressure-decline method, as it has been applied in the Texas Panhandle Field, does not give consistent results (and it does not) that it should either be discarded entirely or interpreted in the light of the definite trends which the application of the method discloses. (Vol. XCI, p. 13912.)

Hughes further testified on cross examination (Vol. 78, pp. 11471; 11499-11508) as follows:

Q. Then you can't recall exactly what percent porosity —have you ever tried to compute the per cent porosity for individual wells of the Texas Panhandle field?

A. I must have done it at that time on those I was working on. It was necessary if I used a porosity on those wells that I was studying at that time.

Q. I thought you just told me someone else did that

A. Do you mean, did I attempt to make the laboratory determination?

Q. That is right.

A. No, I have never done that. I didn't mean to give you that impression.

* * * * *

Q. Doesn't this estimate of reserves involve the fundamentals of physics as you have applied the method here?

A. Yes, I think so.

Q. Have you any authority, any publication, any scientific journals, any text books, which would sustain you here?

A. It might be well to read what I said in my written statement.

Q. Well, I have read the written statement several times and I don't find—there is no authority cited there.

A. I have tried to describe here what I did.

Q. Of course, I am not interested in what you did right now—I know what you did, but I am interested in what authority you had for doing what you did in the field of physics.

Mr. Spencer: He is giving you his authority in his statement

By Mr. March:

Q. What page are you referring to?
A. At the bottom of Page 5, after I described my observations I go into a little sort of a summary in which I state: "Thus I believe that for practical purposes in the Texas Panhandle permeability varies with porosity."

In the next explanation is stated: "Virgin natural open flow is an important index to original gas content because reserves are governed by pressure."

The pressure in the formation is one of the factors which you must know in order to estimate reserves and they are governed by thickness. Thickness is one of the things you must know. Porosity is another thing you must know, and when we talk about porosity in the oil and gas business we are talking about effective porosity, that is, the interconnected porosity in the formation.

Now, that statement ties in definitely to the use of physics in estimating reserves. Then the next statement is "Open flows are governed by pressure." Pressure is one of the things that influences open flow.

Referring back to the first observation on reserves, that pressure is the same in both cases.

"Open flows are governed by thickness." That ties in to direct observation in the field and it has its reasons in physics why that is true.

"Open flows are governed by permeability." Of course, back in that permeability relationship comes porosity, because you can't have permeability unless you have some effective porosity, so that the two start out from a common point. No porosity would have no permeability and then end up with a common point where under given sizes your permeability would be greater if your porosity was greater.

I think all of those statements are tied in to physics and the way I apply that to the Texas Panhandle field is then tied into my practical experience in the Panhandle which I have explained in this report.

Q. That was very interesting; however, I want to get to the point of my question. I notice here on Page 6 you say: "Permeability (for practical purposes, in the Texas Panhandle field this varies with porosity)."

Then you have at the top part of the page: "Porosity (for practical purposes, in the Texas Panhandle varies with permeability)."

Can you show me any scientific books, any scientific text books on physics which sustains any such direct relationship?

A. Well, I don't think I can show you any that states that there is a direct relationship in all cases. I don't know that I could show you a quotation that would necessarily state that there is a direct relationship in some cases. I know I could show you cases where it shows there wouldn't have to be a relationship. I have—

Q. Well, I have done a little—

Mr. Spencer: Well, let him finish his answer, Mr. March.

Mr March: All right, proceed with the answer.

The Witness: I think that I have tried to explain that my practical observations in the Panhandle field allow me to conclude that there is a relationship.

By Mr. March:

Q. Is that your complete answer?

A. Well, up to this point.

Q. All right, sir. Now, I have done a little studying myself here on this subject—

Mr. Spencer: Are you testifying now?

By Mr. March:

Q. Who would you say had written the outstanding work on this subject of permeability and porosity?

A. Well, I wouldn't want to say right offhand.

Q. Do you know anybody that has written any books on it?

A. Yes, I know several. I don't know them, no.

Q. I mean, do you know who they are?

A. I know some of the names, yes.

Q. Name one.

A. This isn't a guessing contest.

Q. No, it isn't, but it seems to me, as you state, that the thing is based on some very fundamental laws of physics—the whole theory.

A. The theory is but the practical application isn't.

Q. I have in my hand here "Flow of Homogeneous Fluids" by Muskat, published in 1937—M. Muskat. Have you read that book?

A. No, I haven't.

Q. You mean you have made a careful study of this question of permeability and porosity without reading one of the leading authorities upon the subject?

A. I have made a study of it in its application to the Texas Panhandle field.

Q. Do you agree with this statement of his?

Mr. Spencer: Now, just before we do that, Mr. Examiner, there is no testimony in the record that this is a leading authority on the subject.

Mr. March: It doesn't have to be the leading authority.

Mr. Spencer: You said it was.

Mr. March: He said he didn't know whether it was a leading authority or not.

The Trial Examiner: No, you didn't ask that.

By Mr. March:

Q. Well, is he one of the leading authorities on it?

A. To be perfectly frank, I don't know.

Q. Would you agree with this statement of his on Page 12?

The Trial Examiner: Do you know the author?

The Witness: Yes, I have seen the name and I know who it is he is talking about, but I have never read the book.

By Mr. March:

Q. You know he is an outstanding authority in the field of physics, don't you—Morris Muskat?

A. I don't know for sure. I assume that he is.

Q. I see. I will ask you if you agree with this statement on Page 12. If you do you can say so. If you don't agree with it you can say so. After some discussion, it states this:

"It will be noted that since the porosity is the ratio of the volume of the unit pore to that of the unit cell (Table I), it will be independent of the radius R of the uniform spheres comprising the assemblage. However, the permeability of the array is dependent upon the actual dimensions of the pore openings and is proportional to R. Thus the porosity of an assemblage cannot alone provide an accurate indication of its permeability. This lack of proportionality between porosity and permeability even in the ideal case is in itself sufficient to eliminate any possibility of deriving significant permeability estimates from porosity measurements."

Do you agree with that statement?

A. Well, I would have to study that.

Mr. Keffer: May I suggest, Mr. Examiner, that Mr. Hughes be given an opportunity to study this text. He is picking out a statement there and I don't know, there may be many things in there that will conflict.

Mr. March: He may have that opportunity.

Mr. Keffer: I would like to have him do that.

Mr. March: I will not ask any more questions until he has done that, but I would like to have him consider this footnote:

"Yet strangely enough, until recent years, the terms themselves were even used synonymously by some engineers, probably because the porous media with which they dealt showed in general that permeability and porosity varied in some manner."

Now, here the book is.

The Trial Examiner: Mr. Hughes, have you ever read any text books on the methods that you employed in this field?

The Witness: I don't believe that the method that I use has been described specifically as such in a text book. No, I don't think—

The Trial Examiner: It is your own method that you have worked out the mechanics of as I understand it.

The Witness: Yes, the straightforward direct application that I use here, yes.

Mr. March: There is only one other matter I want to mention along this line.

Q. I haven't been able to find, and I will be frank to admit, any scientific backup for your exhibit. There may be some and I am coming to the details of the application of the exhibit in just a minute on its merits.

I have studied and I have here the "Pennsylvania State College Mineral Industries Experiment Station, Folder No. 12," proceedings of the Third Pennsylvania Mineral Industries Conference, Petroleum and Natural Gas Section held at the Pennsylvania State College May 5th and 6th 1933 and I will let you take this and study it, too. I want to ask you if you agree with a statement in here regarding the subject.

First I want to know if you agree with the definitions and see if we have a common understanding of the definitions:

"Permeability is that property of a solid which makes possible the transport or conveyance of fluids by and through it; in other words, it is a measure of the fluid conductivity of a solid."

Mr. Spencer: Now, Mr. Examiner—

By Mr. March:

Q. Do you agree with that definition of permeability?

Mr. Spencer: Before you answer if he wants him to express his opinion on a lot of random reading from text

books here, I suggest that he designate what he wants an opinion on and give the witness a chance to look at the text book.

Mr. March: I will give him a chance.

Q. Then I want to know if you agree with this definition of porosity:

"Porosity is that property of a solid which makes possible the storage of fluids within itself; in other words, it is a measure of the fluid capacity of a solid."

Now, that is found on Page 66.

Now, near the end of this scientific publication, Page 140, we find the following statement, and I will ask you if you agree with it and you can take your time about answering it:

"The data emphasizes the fact that there is no direct and simple relation between porosity and permeability. This fact cannot be emphasized too strongly in view of the prevalent impression even among technical men and engineers that there is a relation or worse yet, that the two are equivalent. The sample of maximum porosity did not possess maximum permeability, although it can be expected that a relatively large increase in effective porosity in many cases is accompanied by an increase in permeability of considerable magnitude. However, the reverse is frequently true, also."

That is on Page 140.

Mr. Spencer: I wonder if we have a note of those.

Mr. March: That's all there is. That's all I could find.

Mr. Spencer: I am glad of that. I wouldn't want to get down to a battle of text books here.

By Mr. March:

Q. And I will still give you an opportunity if you see fit on my cross examination to cite me any authority in any text book or publication on the field of physics for your theory.

A. That is on the strict relationship between permeability and porosity.

Mr. Hughes further testified on cross examination (Vol. 85, pp. 12676-12703) with respect to the relationship of porosity to permeability, as follows:

Cross Examination (Continued).

By Mr. March:

Q. Mr. Hughes, you have had an opportunity to study those two books I gave you. One was Muskat's Flow of Homogeneous Fluids and I asked you if you agreed with the statement I read into the record from Page 12 of that book. I will again ask you that question.

Mr. Spencer: Mr. March, do you think we should have the statement read into the record again at this point?

Mr. March: The statement was read into the record on Page 11504 and 11505 of the transcript. I think that will suffice, but he can read it into the record again if he so desires.

Mr. Spencer: I am not insisting upon it if it is sufficiently identified.

Mr. March: I have the part that was read into the record right here.

The Witness: I don't remember exactly the portion that was read into the record.

By Mr. March:

Q. Do you have Page 12 there?

A. Yes.

Q. You might read here, starting with "It will be noted * * *" the top paragraph on Page 12, and the footnate 2 on page 12.

A. "It will be noted that since the porosity is the ratio of the volume of the unit pore to that of the unit cell * * * it will be independent of the radius R of the uniform spheres comprising the assemblage. However, the permeability of the array is dependent upon the actual dimensions of the pore openings and is proportional to R^2."

Wait a minute. That has a 2. It looks like R^2. The 2 refers to the footnote. That should be "proportional to R."

"Thus the porosity of an assemblage cannot alone provide an accurate indication of its permeability. This lack of proportionality between porosity and permeability, even in the ideal case, is in itself sufficient to eliminate any possibility of deriving significant permeability estimates from porosity measurements."

I want to correct myself again. There is another "2" after that, so I am quite sure back up there the "R" should have read "R^2."

Q. You forgot to read footnote 2.

A. Yes. The footnote says: "Yet strangely enough until recent years the terms themselves were even used synonymously by some engineers, probably because the porous media with which they dealt showed in general that permeability and porosity varied in the same manner."

May I make some comment here?

Q. First I want to know if you agree with that statement?

A. Yes, I agree quite definitely with this statement and I always have recognized that porosity and permeability did not need to vary together and this book is a lengthy treatise that shows the mathematics of why they do not need to, although all through the book he recognizes the relationship—a relationship. That relationship starts from the very fact that in order to have permeability you must have some porosity and coming back to this sentence in the first paragraph I just read where he says: "Thus the porosity of an assemblage cannot alone provide an accurate indication of its permeability" shows what I mean. These authorities definitely recognize the relationship but approve very distinctly and to great extent with very advance mathematics why that is not true, but the significance of what these theoretical treatises have to do with the actual field experience and field practice is brought out, I think, in this footnote where he says: "Yet strangely enough, until recent years, the terms themselves were even used synonymously by some engineers." At that point we have a highly theoretical—the author of a very highly theoretical treatise on the subject, you might say, is not condemning them for using the term "synonymously," but pointed out they

did use the term "synonymously;" that is, the terms "porosity" and "permeability," and I want to point out we have not done that. We have not used the term "synonymously."

He also points out why they were doing that, because in the very same sentence he says: " * * * probably because the porous media with which they dealt showed in general that permeability and porosity varied in the same manner."

My interpretation of that statement is that he definitely recognizes that these engineers out on the job and dealing with actual practical examples had found that the "porous media"—I am using his very words—"with which they dealt, showed in general that permeability and porosity varied in the same manner."

At that point my experience in the Panhandle field fits in with his statement; however, I want to make it very definite here again that this has to do with the very strictest interpretation of how porosity and permeability go along together.

Now, I haven't made any claim that in my treatment of reserves in the Panhandle field that porosity and permeability do have to go along on a very hair-splitting straight line relationship. In fact, my zone map is not a map of permeability. My zone map is a map of open flow. A relationship is constantly between open flow and reserves and not between permeability and porosity. The relationship between permeability and porosity is only one of the factors that enters into what open flow really is.

My relationship, and it is shown on my zone map, is the relationship between open flow and reserves in place.

Q. Now, I asked you in regard to the other book you have there, the publication, referring to Page 6—

A. May I point out one more thing?

Q. Surely. Go right ahead.

A. I have one more citation—

Q. Wait just a moment. Is that citation from Muskat's book on "Flow of Homogeneous Fluids"?

A. Yes, sir.

Q. It is from this book you have here?

A. Yes. By the way, I didn't make these marks on this book. I notice there is a warning in the front of this book. It says: "Whoever writes in, tears or injures in any way a book belonging to the Denver Public Library may be punished by fine from $2 to $25," and I definitely didn't make the marks on this book.

Q. Confidentially, I didn't either.

The Trial Examiner: Will you serve a copy of this page to the library when it is returned?

The Witness: On Page 80 of Muskat's book in the middle of the paragraph there in the middle of the page he says: "While it appears probable that the porosity of a given heterogeneous sand will be the primary property determining the final value of the permeability of the given assembly of sand grains, it is nevertheless not unlikely that the porosity will still not give a completely sufficient specification * * *" my interpretation is that he definitely recognizes a relationship by that "* * *the porosity will still not give a completely sufficient specification * * *" emphasis on the "completely."

That ties in with the bottom of Page 12, with the note on the bottom of Page 12.

By Mr. March:

Q. I will ask you to see anywhere it shows the direct relationship between permeability and porosity.

A. I don't say that it does. I don't demand an absolutely direct one. As I explained before, on reserves in the Texas Panhandle field, it has to do with the relationship between open flows and reserves in place, and the relation between porosity and permeability is only one of the factors that governs open flow. Thickness is another factor. I think I have tried to explain in our experience in the Panhandle, that whatever the permeability might be, if you have a big well, of course, you have a thick pay or a good permeable porous zone.

Now, if you had a well that had high permeability locally but did not have a great amount of void spaces which would be definitely related to thickness and porosity, then

that open flow would not be sustained. The fact is that these large wells, the average large wells in the Panhandle field, do have enough porosity and thickness back of them in order to sustain, and if you had the reverse in that case you would have a freak well that would either be discounted in its apparent open flow or would be discounted in the size of the area that is involved, so again I want to make it very clear that my relationship is on open flow and reserves.

Q. All right, let's come to the next book there, your "Pennsylvania State College, Mineral Industries Experiment Station, Folder No. 12." First I will ask you in regard to the definition of permeability and porosity. I think it is on Page 66 there.

A. There is a definition, yes, on Page 66 of each term.

Q. It is referred to here in the record on Page 11507.

A. Do I agree to those definitions?

Q. Yes. There is also reference to it in the transcript on Page 11506. Do you agree with those definitions of permeability and porosity?

A. I might read those definitions here again:

"Permeability is that property of a solid which makes possible the transport or conveyance of fluids by and through it; in other words, it is a measure of the fluid conductivity of a solid."

"Porosity is that property of a solid which makes possible the storage of fluids within itself; in other words, it is a measure of the fluid capacity of a solid."

Of course, I agree with those definitions in a general way; however, the permeability is dependent upon the effective porosity rather than on the absolute porosity, because in order to have any permeability at all we must have an inter-connection of porosity; that is, the porous spaces must be connected in order to allow the flow through the solid, again showing quite definitely that it is related.

Q. The next one I believe is on Page 140.

A. The next sentence right after the paragraph on porosity states: "The only simple relation between the two is a qualitative one, namely, a solid is permeable by virtue of its porosity."

That is just what I stated in my own words.

Q. Turn to Page 140 and read that paragraph I asked you if you agreed with, beginning with "The data emphasizes the fact * * *".

A. Page 140?

Q. That's right.

A. Is that another one you read into the record?

Q. That is right. That is the main one. It starts with "The data emphasizes the fact * * *" beginning there on Page 140.

A. Well, that very first sentence says: "The data emphasizes the fact that there is no direct and simple relation between porosity and permeability."

I would like to indicate the emphasis on direct and simple relationship. Again that indicates that there is a relation. Now, quoting from that point, do you want me to read the rest of the quotation?

Q. Go ahead.

A. "This fact cannot be emphasized too strongly in view of the prevalent impression even among technical men and engineers that there is a relation, or worse yet, that the two are equivalent."

Of course, I haven't made any contention that the two are equivalent. It states further: "The sample of maximum porosity did not possess maximum permeability, although it can be expected that a relatively large increase in effective porosity in many cases is accompanied by an increase in permeability of considerable magnitude. However, the reverse is frequently true, also."

Again that shows quite definitely the thing that I have observed in the Panhandle field that can quite definitely exist even though their mathematics shows it does not need to exist. I agree right along it does not need to exist and there would be many places where it wouldn't.

Q. I believe that is all of the quotations isn't it?

A. Is that all you wanted me to read?

Q. Yes. Just a minute. You can read any other portions you see fit.

A. I would like to mention one or two more from this

bulletin. I would like to mention, too, that this bulletin from the Pennsylvania State College and a great deal of the other work that has been done in recent years on permeability and porosity has to do with the problem of secondary recovery of oil from old abandoned oil fields where the permeability relationship is much more amplified with respect to a viscous fluid like oil than it is in a gas field. It is just obvious that the permeability has more to do with a viscous substance like oil, a liquid, than it would on gas. This bulletin from the Pensylvania State College was dated May 1939.

On Page 93 of the Pennsylvania State College bulletin—just a moment. Is that the same article?

A. Yes, it is the same treatise, Bulletin 12.

Q. All right, go ahead.

A. Near the bottom of the page it says: "The results seemed to indicate that permeability was related to porosity in grain size, and a plot of the permeability versus porosity defined a curve. From a knowledge of results in the field the conclusion was drawn that in the Bradford and Richburg areas porosity is a criterion of permeability."

These conclusions—you want to see if I am reading this word-for-word, do you?

Q. I just want to see what page you were reading from.

A. "These conclusions are concurred in by Barb * * * and Barb and Branson * * * in presenting an equation defining the relation between these factors for the Bradford sand of average grain size as a result of many tests."

I think it is evident that they recognized a relationship.

In the middle of Page 94 they state: "There seemed to be a parobolic relation between permeability and porosity."

In that case the word "parobolic" refers only to the shape of the curve which is a curve relationship as stated in the citation that I just read to you previously.

On Page 170 of the same bulletin under "Discussion," Mr. Pierce—

Q. Is that a part of the transcript you are reading?

A. It is under "Discussion."

Q. This isn't a part of the article of the scientific studies I quoted from, is it?

A. It is a part of the bulletin quite definitely. It is a discussion by the various members in session.

Q. Go right ahead.

A. It is published here as part of this bulletin we are talking about. Mr. Pierce says: "I have long been a radical on condemning engineers who relate porosity to permeability only. Now I am in the position of coming back to their aid. I feel that Messrs. Fancher and Lewis go too far." They were the authors of this treatise preceding these pages.

It states further: "It is not true that there is no relationship with a definite substance there is a relationship."

Now, again I want to point out the fact that those men in dealing with the highly mathematical reasons why there would not need to always be a relationship have found in their contact with practical engineers and geologists with conditions out in the field that those engineers have been realizing a definite relationship for a long time. It is quite evident that what he says is significant in what I have done.

He says: "With a definite substance there is a definite relationship." Just a minute. I want to correct that It says: "With a definite substance there is a relationship." That is exactly what I have found in the Panhandle, but again I want to point out that relationship is not the sole governing factor that entered into my observation of a definite relationship between open flow and reserves. This thing we are talking about in these bulletins is the very very strict relationship between porosity and permeability.

Now, there is another citation—

Mr. Keffer: May I ask a question here, Mr. March?

Mr. March: Yes.

Mr. Keffer: Do you know that the Mr. Pierce you quoted from there is Homer Pierce or H. R. Pierce from the Bureau of Mines? If you don't know, that is all right.

The Witness: I couldn't tell you definitely.

Mr. Keffer: All right.

The Witness: I am trying to see if these men who took part in this discussion have their relationship set forth, but I don't see it here.

Another citation is on Page 171 in this "Discussion." It is by Mr. Hogg.

By Mr. March:

Q. Is that a part of the transcript?

A. Yes.

Q. What page is it on?

A. Page 171. It states: "With reference to Mr. Pierce's remarks, it is possible that there is more of a relationship between permeability and effective porosity than between permeability and absolute porosity."

Of course, my explanation a moment ago would definitely indicate that I agree with that, that the relationship of the—at all times when we are talking about the porosity of a reservoir, we must talk about the effective porosity, because if there is a part of the porosity that is not effectively interconnected with the reservoir or whatever might be in it would never be an effective part of the reserves that we would be talking about; that is, if it were sealed off it wouldn't be a part of the reserve that we would want to be discussing.

On the same page, Doctor Fancher in this same discussion and one of the authors of the paper, says: "Permeability is some function of porosity providing we consider other factors. High porosity does not always mean high permeability. There is in general an increase of permeability with increase in porosity but the relationship is perhaps an exponential and complex function of other variables as well as porosity."

There again he recognizes relationship between permeability and porosity and again I want to point out that this relationship has been recognized by engineers who are out on the job in the field and his technical discussion recognized that fact, that engineers have noted the relationship; and as I pointed out, Muskat, you might say, took the engineers to task for observing the relationship in the media they were dealing with but for using the term "synonymously."

Q. Nobody is going to deny there is a relationship but I challenge you to show *me* anywhere in this book where there is a direct relationship.

A. I told you a while ago I didn't say that there was and I do not demand from my treatment of what I am doing with open flow as related to reserves of gas in the Panhandle field that the relationship there is dependent upon porosity and permeability only in part. Therefore, that relationship would not have to be a straight line, definite hair-splitting relationship. I am dealing with wells in the field, with averages of wells of the same size and type where the thicknesses and these permeability relationships tend to average out.

We even noticed the samples that were employed in detail from the one well, the Shell No. 3 Haggard, showed that even within that one hole that the permeabilities varied so that we are dealing with the open flows of wells and back down in the formations from which those open flows are controlled we have averages and we have the ranges from low to high both in porosity and permeability.

Mr. Keffer: From the same well?

The Witness: From the same well.

By Mr. March:

Q. I will challenge you to present any scientific proof from published scientific journals where the open flow indicates gas in place.

A. I will be glad to do that. I want to refer you right at that point to the report of investigation 3313 of the United States Bureau of Mines. The title of that bulletin is "Extent and Availability of Natural Gas Reserves in Michigan 'Stray' Sandstone, Horizon of Central Michigan."

This report is by E. L. Rawlins and M. A. Schellhardt. Now, you challenge me to show you where in the text there is a relationship between open flow—

Q. Direct relationship between open flow and gas in place.

A. We have left the porosity and permeability relationship and have gone to the very thing I am talking about in the Panhandle field of Texas.

Q. That is right. Proceed.

A. In this report they make an estimate of gas reserves in the Michigan stray sandstone zone horizons of Central Michigan. They make these estimates on the porosity thickness method. Now, in order to make such estimates you must arrive at your porosity. I will come to that in a little bit here. You must also have thickness.

On Page 11, the third paragraph—I am reading from this report—it states: "Two principal methods of analysis have been used in this report to determine the average productive thickness throughout a field. The first method is based upon an average of the interpreted productive thicknesses of the individual wells in the field being studied.

"The second method is based upon an interpretation of average open flow volume per foot of productive thickness. Ordinarily, for thicker productive lenses than occur in Central Michigan a study would be made of the open flow volume per square foot of productive formation exposed in the drill hole, but for the comparatively thin productive sandstone lenses in Central Michigan fields it is believed that an interpretation based on the open flow volume per foot of productive thickness is satisfactory."

I want to explain in detail just what that means. It means quite definitely that in order to estimate reserves in the manner in which he did, using the porosity thickness method, in order to arrive at the reserves he must have a porosity figure and he must also have a thickness figure.

Now, in this explanation it shows quite obviously that he arrived at thicknesses in individual wells that were studied and in some wells where the thicknesses were unknown to him he used the open flow as an indicator of the thickness.

Now, in order to have a porosity to go along with that open flow or with that thickness, I want to quote how he found the porosity. I am reading now the paragraph under "Porosity" near the top of Page 8 in this report:

"Cores have not been obtained from any wells in the Clare, Hinton-Millbrook-Belvidere, Home-Richland-Day or Ferris-Crystal areas, and consequently porosity tests applicable to these fields have not been made. A porosity test on a sample from one well in the Vernon field indicated a porosity of approximately 19.5 per cent. Samples of

the productive formations from several wells in the Austin field were tested for porosity in a Chicago laboratory and results averaged about 17 per cent. A sample obtained from what seemed to be a very porous streak in one of the wells in the Austin field and tested at the Petroleum Experiment Station, Bureau of Mines, Bartlesville, Oklahoma, had a porosity of approximately 24 per cent. Reports on samples obtained in the Broomfield field indicated a porosity ranging from 18 to 20 per cent. A consideration of these data indicates that it is reasonable to assume a porosity of 20 per cent in estimating gas resources in the higher parts of the structures and 18 per cent in computing probable reserves farther down the structure."

At that point I want to point out that he has an estimate of porosity. In order to go along with an estimate of porosity in an area where he did not know the thickness of the sand he let the open flow be his guide to what that thickness was and it is explained quite definitely in the first quotation that I read.

Now, the only difference between what he did and what I do is that I don't set up an average porosity to go along with my open flow. If I wanted to follow specifically what he has done, I could go along with each well with an assumed porosity of 20 per cent, say, and by means of the open flow let the open flow give me an estimated thickness and at that point I could use porosity and thickness and it would show the mathematics of the computation arriving at the reserve.

The only difference between what he says and what I do is that I let my open flow be a guide to both porosity and thickness. I want to point out again what he did was, he had an assumed porosity and with that assumed porosity he let his open flow be a definite guide as to thickness.

Right in connection with that, several years ago while Mr. Rawlins was still with the Bureau of Mines and before this report was published—the date of this report is July 1936—at the time I was working for the Cities Service in connection with the Topeka case—as I remember it was in the spring of 1935. I remember I told you the other day the case was in 1935—I had a long conference with Mr. Rawlins who was still then with the Bureau of Mines and located at Bartlesville, Oklahoma.

I explained in detail just what I was doing in the Panhandle field, how I had arrived at the fact there was a relationship between open flow and reserves in place. As I discussed what I was doing in the Panhandle, he very—

Mr. March: Just a minute. I object to that statement for this reason, because my witness wasn't permitted to say what the Phillips Petroleum Company had discovered about the known relation between porosity and permeability. Mr. Hammer was on the stand and I asked him as to the Phillips Petroleum Company showing there was no relationship between permeability and porosity—

Mr. Keffer: Just a moment, Mr. March. We will grant the soundness of the objection, Mr. Examiner.

The Trial Examiner: Very well.

Mr. Keffer: You need not say any more, Mr. March. We have granted it.

Mr. March: I would rather let my man go on.

Q. Is that all of the statement you have about that report?

Mr. Spencer: You interrupted the train of thought of the witness.

Mr. March: Just skip the Rawlins conversation.

Q. Is there any other statement you wish to make? If there is, we will be glad to have it.

A. Skipping the discussion, I can go along and quite definitely state what I have done in the Texas Panhandle field is definitely what he did in the areas of the Michigan field where he had no thicknesses and where he hadn't an assumed porosity, but he let his open flow be the definite index as to the amount of gas in place.

The only difference was, he came around and carried through the mathematics after letting the open flow give him an estimate of thickness, but the result is the same. Had he set up his relationship he could have gone directly by means of a factor from open flow to reserves in place. Just what that factor could have been, I do not know. It most certainly would not have been the same factor that I used in the Texas Panhandle field. I wouldn't expect the

factor I used in the Panhandle field to be the same in another field. That factor would have to be determined; however, I want to point out that he could have definitely gone from open flow by means of the factor to reserve content per acre in place.

Q. But he didn't?

A. I say that the only difference—the result is that relationship—

Q. But he didn't, I said.

A. I could answer that better if I could refer to my conversation with him.

Q. I see.

A. The result is, he did do it. For instance, I could point it out very distinctly that the way I applied a direct relationship between open flow and reserves in place in the Panhandle field at a given well with this relationship between open flow, I could assume porosity and I could calculate by means of that porosity what the necessary thickness would have been, and my answer would be the same as the answer that I do get without calculating it. That is what I am trying to show you, that the only difference between what I did and what he did is, he has recognized this direct relationship between open flow and reserves in place, but he merely went through the mathematics of showing what thickness was necessary in order to accommodate that given relationship. It was an assumed proposition all the way through, based upon the definite recognition of the relationship between open flow and reserves in place.

Q. The field you referred to is located in Michigan?

A. I stated the title of the bulletin.

Q. Those sands are pretty well uniform, aren't they, as to content?

A. No, they are not. I think you could gather from the paragraph that I read that they were not.

Q. You made some very interesting statements here, Mr. Hughes. I believe you stated here that you arrived at the porosity and pay thickness of the Texas Panhandle field by the open flow method of estimating reserves.

A. Would you have that read for me?

Q. I understand the effect of it was—

A. I would like to have it read.

Q. I will ask you the question directly. Did you determine the pay thickness of the Texas Panhandle field?

Mr. Spencer: In connection with the preparation of this exhibit?

Mr. March: In connection with the preparation of this exhibit.

The Witness: I have explained at length what I did, that I arrived at thicknesses and porosities in a group of wells from which point with an observed relationship between open flow and reserves I went immediately from that to the field as a whole with that relationship of open flow to reserves.

By Mr. March:

Q. I want to ask you if you did arrive at the pay thickness for the entire field?
A. No, definitely not. I think that has been clear in the record.
Q. And in arriving at the pay thicknesses in those few wells which you didn't have the names of, I believe you used the same method that Mr. Rawlins uses here in the Michigan field, or did you?
A. May I have that bulletin again?
Q. Certainly.
A. I told you what he does—

The Trial Examiner: We have spent considerable time on that, Mr. March, explaining the difference between what he did and what Mr. Rawlins did.

Mr. March: I just want to ask a few questions in regard to that, Mr. Examiner. If in those early wells he did arrive at the pay thicknesses in the manner Mr. Rawlins did, that is something different than what he did at the beginning, because from what I understand, he had samples to ascertain the pay thicknesses of those early wells he examined. It makes a big difference. I want to just clear that point up.

Mr. Keffer: Of course he said quite definitely, Mr. March, as I understood him, at least, that he didn't apply open flows for the determination of sand thicknesses.

Mr. March: If he will make that statement in regard to the early wells, that is all right.

The Witness: Let me make a statement—

By Mr. March:

Q. Did you use the method Mr. Rawlins has outlined here in arriving at the pay thicknesses of the few early wells?

A. You mean by that method in which he

Q. Open flow.

A. Quite definitely, no.

I want to point out what I did as compared with what he did. I observed the thickness and porosity on a group of wells that started me out on my relationship between the open flows of those wells and the reserves.

Now, I want to point out that that is also what Mr. Rawlins did in Michigan. I have read that quite distinctly in the first quotation from Mr. Rawlins where he says

Mr. Spencer: I don't think there is any necessity of repeating it, Mr. Hughes.

The Witness: All right.

By Mr. March:

Q. Did you know that in the Texas Panhandle field that 5 million cubic feet—strike that.

Q. Did you know that in the Texas Panhandle field five feet of pay may have 10 million cubic feet of gas and 10 feet of pay may have 3 million feet of gas?

A. I haven't in mind at the moment a specific case proving that point, but I wouldn't be surprised at all. I wouldn't be surprised if the contrary were true.

Q. Then your open flow doesn't indicate pay thickness, does it?

A. The pay thickness is one of the things that governs open flow. The other is the porosity.

Q. Yes.

A. And permeability. If you have greater volume from the lesser thickness, naturally you have greater porosity and permeability with that lesser thickness. That is just obvious. It works out that way quite definitely in the Texas Panhandle field.

Q. If your pay thickness had different content, how in the world can you gather anything about reserves in the Texas Panhandle field?

A. Well, I have explained how I arrive at it. Now, at that point it is obvious that pay thickness is not the sole governing factor of reserves and it is not the sole governing factor on open flow. It is only one of the factors.

Q. Oh, yes, there is one other question I want to ask you in regard to this Pennsylvania bulletin. You are aware of the fact that in this Pennsylvania State bulletin these two individuals who wrote this article examined some three or four hundred cores to come to their conclusions?

A. They have quite a list of determinations in the bulletin. Whether they actually did the work or not, I am not in a position to say. There is a list of quite a few determinations of core samples. Of course those core samples are very small and they represent only a few inches of the formation and the core which is used—the actual piece of the formation which is about as big as your thumb or a little larger, that actually goes into the determination of permeability, is not the identical piece of the formation from which the porosity is tested.

Undoubtedly it is from the same general portion of the core. That, of course, is as near the same as they could get it, I presume.

Q. These analyses of cores, three hundred and some odd here, of the authors of the Pennsylvania State bulletin, are similar to that of the Shell Petroleum Company that we discussed, aren't they?

A. Well, they are similar in that they are determinations of porosity and permeability. I have made no attempt to plot those curves or those relationships into a curve.

Q. You are aware, though, are you not, that the conclusions on Page 140 are based upon that comprehensive study on those cores?

A. Let me see the conclusions on Page 140.

Q. You just read them.

A. I don't think those conclusions refer to all of the determinations. They might. I wouldn't want to make a point of that but I want to refer you to the situation that I quoted in which the results of those permeability-porosity *testes* showed that there was a curve relationship. I think I read the citation in which that was stated.

Q. Yes. Now, do you have any other authority, do you think, to support that open flow indicates gas in place?

A. Well, I wanted to clear up one thing just a moment there. You said that I have read those bulletins. I did not read either one of those books completely word for word. I have not read those.

Q. Did you read the Pennsylvania State bulletin?

A. I skimmed through it but I don't want it left in the record that I read and made a complete study of that bulletin, word for word.

Mr. Hughes further testified on cross examination (Vol. 79, pp. 11650-11653) as follows:

Q. The permeability has a lot to do with the reservoir condition, doesn't it?

A. The reservoir—the porosity is one of the definite factors that determines permeability. The porosity and thickness governs the reserves.

Q. Have you ever made a study to ascertain what the thickness is in those two wells?

A. No, I haven't.

Q. How do you know one has a higher thickness than the other?

A. I think I explained in the beginning that my observation was that open flow was dependent upon thickness, and permeability, which was tied in definitely with porosity.

Now, from that statement I have explained—if I haven't explained it clearly I want to make it clear now, that the reason I went from that observation to the rest of the field from the area where I knew that relation was—I went to the rest of the field on a direct relationship by means of open flow—that it was largely because I didn't have these other figures on those other areas of the field.

"These other figures," by that I refer to the thicknesses. As I went from my known areas to the unknown areas I let my open flow be my measure, my index, which covers both thickness and porosity, that is exactly what I did, so except just for curiosity I would have no reason to examine those particular wells as to what thickness the log might have shown or whether it showed any thickness or whether it was a reliable record or what.

Q. So you used this method of estimating reserves be-

cause you didn't have reliable data to estimate the reserves on the pay thickness and the porosity method?

A. If I knew specifically what the thickness was in every tract in that field and knew what the porosity was on every tract in that field, I wouldn't need to use any other method.

Q. Isn't it true the reason you can't apply the porosity thickness method is because you can't secure accurate thickness and accurate porosity for the entire field?

A. I won't make that broad a statement. I will tell you what I did—

Q. Yes.

A. I realized that I had some test areas in which I felt that I knew what the thicknesses and the porosities were, and after finding that they were related to open flows, then whether I made a detailed search to prove that the thicknesses were available or not, I went on to the unknown areas by means of open flows.

The fact that I have done that doesn't necessarily prove that what you said a moment ago was true, that is, that you don't have enough thicknesses. I found at that time that it was very difficult to know in many of the other instances what the thicknesses were and what the porosities were, and it was a matter of convenience and necessity that allowed me to conclude that my relationship was true and to go ahead from that, from the known into the unknown by means of open flow.

Q. Of course, you can't name me a single well which you conducted those experiments on?

A. I told you yesterday that I did not have a list of those wells, but the observations were definitely made. They were made by me a number of years ago.

Q. I have made some sort of a study of some pay thicknesses which have been prepared by some geologists. Have you examined those pay thicknesses made by those geologists?

A. I have discussed them at length.

Q. Have you examined the pay thicknesses?

A. I heard you read a lot of them. I have seen a list of them but I haven't made an attempt to check them, if that is what you mean.

Q. Have you—if you checked one of those and found you had a 50 million open flow well with a lower pay thickness than a 25 million open flow well, that would indicate to you in the case of the two particular wells there was no direct relation between the pay thickness and the open flow?

A. It would indicate to me the well that had the same pay thickness with a little larger open flow would have more porosity.

Q. That is the only conclusion you would want to draw?

A. That is the pertinent conclusion.

Q. If the well had more than a 20 per cent porosity, an open flow well, what would you say?

A. I would say it had more than a 20 per cent porosity.

Q. Do you know of any laboratory test by which you can determine the porosities of gas wells in the Texas Panhandle field?

A. I think we discussed that at length yesterday.

Q. You don't know of any?

A. Yes, I described some. You can read in the record what I said about that yesterday.

Q. I asked you to give me a single well in the Texas Panhandle field where there were laboratory tests on the samples taken from that well where the porosities had been determined by anybody.

A. You mean the complete porosities?

Q. I mean the porosities of the pay formations.

A. No, I agreed with you I didn't know of any cases of that sort.

* * * * *

Mr. Hughes further testified on cross examination (Vol. 80, pp. 11849-11850) as follows:

Q. I come next to the next Shamrock well, it is the Garland-McKee well, located in Section 399, Block 44—the same block as the other—and H & T C Survey, with an open flow of—my record shows 160 million but I don't have those records here, and your record shows as I see it, 155 million.

A. There is a well. I have a well in that section.

Q. 155 million?

A. 155 million, yes, sir.

Q. Now, Mr. Hughes, I want to know if in making up your averages for these zones you included that Shamrock well in the average.

A. Well, what is the date of the completion?

Q. The date of completion of that well is 5-13-38.

A. 5-13-38?

Q. Yes, sir.

A. I wouldn't definitely know without the—the same applies to that that I made on the wells just before. I am inclined now as I look back and reconstruct what went into the picture that I have painted on those zones—I doubt very much if I would have used it according to what I know about those wells today, I know that I wouldn't have used them if I had known about them then what I know about them today.

Q. What in the world did you put that open flow up there on your map as being your open flow for, then?

A. I explained that, too.

Q. Did you correct that back to virgin open flow conditions?

A. I doubt it.

And again, (pp. 11869-11870, Vol. 80).

Q. I notice here in these two examples which you have set forth you have used in both cases a 20 per cent porosity.

A. Yes, sir, in the example.

Q. I notice that in one case you use a 40 foot pay thickness and in the other case a 20 foot pay thickness, is that correct? For the large well of 10 million open flow you used a 40 foot pay thickness and for the small well of 10 million open flow you used a 20 foot pay thickness, is that correct?

A. Yes. You mentioned the small wells. The smallest well is 5 million, isn't it?

Q. Yes. Mr. Hughes, I thought you told me when we approached this the other day you couldn't recall what pay thickness you used in your original calculations.

A. I don't. That is an example. Those are examples of what I was talking about.

Q. This is not any particular well?

A. Absolutely not.

Q. You still don't know whether you used a 20 per cent porosity and a 70 foot pay thickness?

A. It shows there I didn't use a 70 foot pay thickness.

Q. Against what size well would you have used it?

A. It depends. I used what I observed at the time.

Q. Do you mean to say that these examples are actual wells?

A. No. I thought I made that plain. In case they are, I didn't intend to show that they were. They were given as examples to show how the formula—it is shown in Example 1 and it is shown in Example 2.

Q. Now, then, you cannot tell me the pay thickness which you used?

A. No, and I told you that the other day many times on the individual wells, but I did it and I did it on a number of wells and I convinced myself I was doing a right and reasonable thing.

Q. Can you show me any place in the Panhandle field where you have two wells right close together where the smaller well has half the pay thickness of the larger well?

A. I think I could but right offhand I don't know. It might work out that way. It wouldn't have to.

And again, (pp. 11878-11879, Vol. 80),

Q. Yes, but I want to know the answer to a very simple question. I want to know why you haven't tried to apply the porosity thickness method to the entire field in arriving at your factor.

A. You know that, as well as I do and it has been stated there are many many wells in the field that you can't find out what the thicknesses were. The records were poor and they were not carefully watched, and a lot of wells were drilled by operators that weren't particularly interested in trying to get details of that nature. There are many many wells in the field that I wouldn't attempt to tell what the thickness was, however, I do know what their volume open flow was and I have explained how I have interpreted those open flows and I show what interpretation caused me to arrive at that.

Q. We are at the first step now we take in getting your 1-1 factor.

A. Yes.

Q. You arrive at the 1-1 factor by using the porosity thickness method on some wells on some parts of the field which wells you cannot tell me specifically?

A. That is right.

Q. Or the pay thickness or porosity? You cannot tell me specifically?

A. That is right.

And again, (pp. 11895-11905, Vol. 80.),

Q. Here is my question: It is very simple. Did you at any time in the preparation of these two exhibits here apply the pressure decline method to the whole field in trying to arrive at your factor? You can answer that question very simply.

A. I have told you that I have been applying the pressure decline method to the entire field for a number of years.

Q. In the preparation of this exhibit?

A. Well, naturally it was prior to the exhibit, because I have been doing it for a number of years.

Q. Well, what was the pressure that you used—the average pressure that you used?

A. Do you want to know from me if I have gone through the arithmetic of taking the production from the Panhandle field at a given date and taken the weighted average pressure of the Panhandle field at that same date and make the bald application of the pressure decline method? Is that your question?

Q. Yes, without inserting a per acre content before you start.

A. Yes, I have done that on a number of occasions.

Q. Let's do that right now, using your own production figures, assuming that they are right. All right, in Exhibit 212 you have a production figure as of August 1939, the total withdrawals as I see it, of 7,485,066,520 Mcf.

The Trial Examiner: You are talking about Exhibit 211?

Mr. March: Exhibit 211.

You have that as your withdrawal figure, do you not, at 16.4 pounds?

The Witness: That's right.

Call it 7½ trillion in round numbers.

Mr. Lange: Page 15, Mr. Examiner.

The Witness: Call it 7½ trillion approximately. If I am going to identify it—do anything with a slide rule, that's about as close as it would be on the slide rule.

By Mr. March:

Q. All right, sir, Then, next, I believe the virgin pressure is 430 pounds. We can assume that, can't we?

A. Yes.

Q. All right, sir. Now, the Texas Railroad Commission weighted areal pressure for the entire field for the summer of 1939 is, according to my figure taken from the Railroad Commission, 323.7 pounds.

A. That sounds about right. I have it here. I think that is it—323.72, July, 1939.

Q. All right, we'll take that as our average weighted areal pressure. All right, you subtract, do you not to get your pounds lost—430 minus 323.7?

A. Yes, that's right.

Q. All right, and what do you get?

A. 106.28 pounds.

Q. 106.3 pounds?

A. That's close enough.

Q. You divide, do you not, your 7½ trillion by this 106.3 pounds to get your per pound drop?

A. You can, yes.

Q. Well, do that, will you?

Mr. Keffer: May I have an understanding at this time with Mr. March that when he goes through this complicated computation that you will give the witness an opportunity to explain in connection with it why this sort of computation cannot give the right answer, otherwise, I am going to object.

Mr. March: I will give him an opportunity to make a lecture on it.

Q. What answer do you get?

A. How's that?

Q. What answer do you get?

A. You are trying to get the production per pound drop?

Q. Yes.

A. That is $7\frac{1}{2}$ divided by 106.3. That gives you about $70\frac{1}{2}$ billion per pound drop.

Q. Yes.

A. Yes—70.5 billion in round numbers. I am reading from this.

Q. Now, right there, where is your similar figure that you calculated out here by your method of open flow, indicating gas in place?

A. My figure doesn't indicate gas in place. My figure indicates original reserve.

Q. All right, you don't have a per pound drop figure and you don't have those figures in existence, is that right?

A. My estimate of gas in place would be the difference between that original at this stage—

Q. All right, now, the production per pound drop—now, we'll calculate the remaining reserves to zero pounds wellhead and is it not correct that you multiply your 323.7 to your average pressure.

A. It just so happens in the Panhandle it is not correct to do what you are doing, but we will do it for arithmetic.

Q. You said you checked your method against the pressure decline method. I am not saying this is not an application of the pressure decline method in the Panhandle field.

A. That will be covered in my speech.

Q. All right, I want to give you the opportunity to make that speech.

All right, you multiply your weighted average pressures by your per pound drop to get your remaining reserves, do you not?

A. I am following your instructions.

Q. Well, don't you do that?

A. Well, we are doing it in this arithmetic, this arithmetic we are doing now.

Q. Isn't this the application of the pressure decline method to the Panhandle field of Texas?

A. It might be your application, but it certainly is not mine and I can give you many reasons why after a while, and I know what the answers are going to be.

Q. What's it going to be—about 30 trillion?

A. I have done it many times. I have been doing it for years.

Q. All right, now tell me this: Just wherein did the way that you apply the pressure decline method in checking your factor differ from the way that we are applying it?

A. Apparently I didn't make it clear in my explanation but the explanation did make it clear. I made it as clear as I could.

Q. The only difference is you started out with your per acre content.

A. Pardon me.

Q. The only difference being that you started out with your per acre content?

A. Yes, I started out with what I thought to be the per acre content and it turned out that in applying it in that method the application of the pressure decline method showed that it was a reasonably correct figure, too, but this is not going to do it.

Q. All right, then I will let you tell me when we get through here just how you did it, just how it is different from this and just why the difference.

Next you multiply your weighted average pressure by your per pound—

A. You want me to multiply 70.5 billion by 324 pounds?

Q. Yes—323.7 pounds.

A. That gives you a product of 22.8.

Q. 22.8. All right, sir, now that is on a 16.4 pounds per square inch basis, isn't it?

A. How's that?

Q. That is on a 16.4 pounds pressure base, isn't it? That answer is on a 16.4 pound pressure base?

A. Yes, it is, because the pressure base of the figures that we started out—

Q. All right, now, you convert that over to a 14.65 pound pressure base.

A. You want me to multiply 22.8 by 1.11 and—call it 1.12—that is the conversion factor to change gas on the basis of 16.4 to 14.65 base. 22.8 times 1.12 becomes approximately 24.15.

Q. I get 25½.

A. Wait a minute.

Q. I didn't get it, I'll confess that.

A. I am used to using my little slide rule that has half the number of divisions on it.

Q. I get 25½ trillion.

A. No, it wouldn't be quite 25½—22.8 times 1.12 gives you 25.3, approximately.

Q. All right, sir, now we have lost this 7½ trillion by withdrawals according to your estimate of withdrawals. I want you now to convert that 7 trillion from your 16.4 pounds pressure base to your 14.65 pounds pressure base.

A. Yes, that would be 7½ multiplied by 1.12. That gives about 8.34.

Q. Now, add up your 25½ trillion and your ~~8.4~~ 8.34 trillion, and what does that give you?

A. 25½—I didn't quite get 25½.

Q. 25.3.

A. 25.3, I believe, and 8.34.

Q. Yes.

A. 8.34. We'll call it 8.3. You get about 33.6.

Q. 33.6 trillion?

A. Yes, that would be trillion.

Q. That would be the original reserve of the Panhandle field of Texas computed by that application of the pressure decline method, wouldn't it?

A. Well, that is your interpretation of it. It is not mine. That is the arithmetic. I am not trying to dodge the arithmetic at all. That is the arithmetic of your procedure that you have led me through.

Q. I used your withdrawal figure, you will admit, though, in doing it.

A. Yes, you used the withdrawal figures that I am using, converted over to 14.65.

Q. All right, I want you to do this for me: I want you to divide there and get the per acre content.

Mr. Keffer: Now, just a minute, Mr. Hughes. Did you understand that question?

The Witness: If he is trying to tack that per acre content onto me—I am going through again the arithmetic.

Mr. Keffer: All right, I want it clear that that is Mr. March's figure.

The Witness: Yes. I am going to divide 33.6 by the acreage of the field as I have used it on this zone map—1,468,329.

By Mr. March:

Q. Is that for the whole field?

A. Yes. So I will divide 33.6 by 1468, and the answer obtained by making that division is 22.9 million.

Q. 22.9 million Mcf.?

A. Yes. We were dealing with Mcf.—no, not Mcf.

Q. I mean cubic feet.

A. We are referring to 22.9 million cubic feet.

Q. All right.

A. This arithmetic that we are going through.

Q. All right, now, do you know any other way of applying the pressure decline method to the Panhandle field of Texas?

A. Yes, I know a number of ways.

Q. I'll let you go into those in a minute, but here you employ this same method and start out with your per acre content of 22.9 million and see what you would come out with.

A. I don't understand your question—your instruction. That was an instruction but I don't understand the instruction.

Q. All right, here is what you say you did:

"From this average *existant* pressure in each of the four zones and having my previously determined original gas content of each of the four zones I applied the pressure decline method to each zone and obtained an estimate of the amount of gas each zone had lost."

I want you to start out here and go through the same calculation except that you start off with the per acre content. What answer did you get?

A. You will have to show me how to do that. I don't know how you want me to do it.

Q. Could you work the pressure decline method when you had the per acre content to start with?

A. I have described what I did and I did it, but I don't understand what you mean for me to do with that 22.9.

And again, (pp. 11907-11921, Vol. 80),

Q. Mr. Hughes, you did not intend to state here that you had your per acre content before you start?

Mr. Keffer: I didn't say that.

By Mr. March:

Q. I mean in your formula. You didn't put the per acre content which you had arrived at by your 1. formula in your pressure decline formula when you started to work the pressure decline formula?

The Trial Examiner: Read that question, will you please, Mr. Reporter?

(The question referred to was read by the reporter as set forth above.)

By Mr. March:

Q. Did you utilize your per acre content that you had arrived at by your 1. formula in your pressure decline formula which you refer to here?

A. No, I don't know in what way it would enter into the formula.

Q. All right, now, I want you to tell me here for the record here—this is the best explanation you can make of the way you used the pressure decline method, is it, that you have here?

A. In testing I used it in the method that I have described.

Mr. Keffer: By the way, right there, Mr. March, as you have read a while ago—and I have never read this thing here—as you read, he didn't attempt to say how he applied the pressure decline formula.

Mr. March: If he didn't, I want to know how he did.

The Witness: This part here where you said you hadn't read before, you have to start in with the fact that I had the field divided into zones and I applied the pressure decline in each zone and I left the potential of each zone as an index or a ratio, if you would rather call it that, than to say that I had my previously determined content.

We can forget all about that being a previously determined content if you want to. We can just look at it as though it were a ratio of some content, whatever the content was.

Now, then, when I applied the pressure decline method to that I ended up with a figure that was so near the figure that I had previously estimated was the content of those zones that I split the difference. Now, the splitting of the difference left 1.075, and I had a 1 to start with. We can see what the pressure decline factor would have been.

Now, let's see what that would have been. The difference —I have 1.075 which is the split difference between 1 and something else. I must have had 1.150. Is that the arithmetic on that—1.150 plus 1 becomes 2.150 and divided by 2 is 1.075. Now, that is the degree of difference in the pressure decline method.

Now, at that point if I had not assumed a correct ratio —if you want to call it that for those zones—which I choose to call a previously determined content in this explanation, then that difference would have been much greater than that, and by spreading the difference they wouldn't have come out nearly as close as they did. That is the point I was trying to make that I considered it a reasonable check and the two methods I split the difference so that as I describe in this report that at that stage of my method it was tied in really to both the porosity thickness method and the pressure decline method.

Q. Is there any way it is humanly possible to check those calculations you made on the pressure thickness in arriving at that factor?

A. Well, I don't know that I have constantly been checking them lately.

Q. I mean to arrive at the factor today in this exhibit.

A. I don't have all of the intermediary steps between that point and the .92 but I have tried to tell you that later studies as time goes on—as time goes on those studies keep showing that the factor was a little too high. At present, as I have explained before, my opinion of the factor .92 that I am using is that it is a fair and reasonable one but that the information that I have as to the way the field is performing since I last made the study which re-

sulted in the .92, it indicates that that factor could be revised somewhat downward.

Q. I don't want to bear on this much longer. I would like to have you come over to this map and show me very briefly how you utilized the perssure decline method in estimating the reserves of the Texoma Natural Gas Company.

A. I have explained that in detail.

Q. Take it up zone by zone. You take your red zone and do what? Take it zone by zone. Take one zone and that is the way you do all of the zones—

Mr. Keffer: Mr. Examiner, the witness has described how he checked his factor against the pressure decline method. I don't know that he can say any more about that.

I will state this to the Examiner and to Mr. March, that Mr. Hughes *as* now in the course of preparation—it is not ready to be submitted and I am quite certain he is not ready yet to testify concerning it—a rather elaborate set of figures and computations upon the pressure decline method which will answer every question.

Mr. March: In that case there is no need to go any further with that line of inquiry.

Q. We are now to your .075 factor. You state here that in getting your .9 factor you have mentioned here 200,000 worthless acres of land. In what respect do you mention that 200,000 worthless acres of land?

A. After I explained how I tested my porosity thickness open flow method by means of the pressure decline method, then I changed the subject entirely as indicated by the fact that I have given the following paragraph a new number. It shows that I am starting now to explain some other things in connection with the history of the development of my estimate of reserves.

We left completely the discussion of the relation of how I tested the idea and the method with the pressure decline and we have gone now to an entirely different subject. That subject is shown in Paragraph No. 12 and there are several paragraphs following it on Page 5 of Exhibit No. 238.

Q. You just tell me in what respect you utilized the 200,000 acres.

A. I will explain it. This tells it in words I thought over during my leisure time.

Q. If that describes it, you need not read it.

A. "This method has been refined from time to time. The greatest refinement comes with the completions of new wells giving more complete information on the exact zoning of the field by potentials and by increasing the number of places in the field that known pressures may be obtained during each field-wide survey for pressures.

"Prior to 1937 I used my own idea as to the outline of the gas field but in 1937 I decided to accept the Texas Railroad Commission's outline of the field as exhibited on their pressure map."

You asked me that date the other day and I didn't remember it for sure but I have just read it.

"In doing this I had to include more than 200,000 acres of land which I had considered worthless for gas, and which I still consider worthless."

That goes on and has nothing to do with the testing of the pressure decline method against the porosity—

Q. What did it have to do with getting the .9 factor?

A. It didn't have a thing to do with the .9 factor.

Q. Let us see what you say in regard to the .9 factor. You state: "Additional refinements have come with subsequent balancing of estimated amounts of gas having gone out of the five zones, zone by zone, and totaled for the whole field, against the production figures from the whole field at a given date. This subsequent testing of the method has resulted in changes of the factor to the present one which is .919211."

I want to know where that data is where you balanced the production from these various zones and arrived at the .9 factor. I haven't seen it.

A. No, I don't have that, and as I have stated, that was the date in which these number of different tests had arrived at the time I used the .92.

Q. It is not in existence?

A. I don't know that it is in existence. I don't have it

here. I have several others that I have made since and I don't have them here.

Q. I want to see the ones you utilized in getting at this .9 factor because I can't test the .9 factor unless I have it here.

A. I told you I haven't it here and I have a number of tests of that factor.

Mr. March: I want the one you utilized in arriving at this factor and I will request counsel to make that available for me to examine.

Mr. Keffer: I do not know how we are going to get something that is not in existence. I will do my best but you won't want me to manufacture one for your special purposes, will you? You don't mean to imply that, do you, Mr. March.

Mr. March: You haven't manufactured one, have you?

Mr. Keffer: No, I haven't, but you are very insistent that one be furnished after the witness says that it isn't in existence. I don't know how I am going to do that unless I make one. You wouldn't want me to do that, would you, Mr. March?

Mr. March: If it is not in existence, I can't get it and I cannot test the factor.

The Witness: May I explain, a moment ago in reply to your remark that I could make a speech?

Mr. March: Wait until I get through questioning you—

The Witness: The explanation that Mr. Keffer gave to the Examiner a moment ago will take care of that speech business.

Mr. March: That is fine, very fine.

Q. In this Topeka case we referred to the other day, I requested you to find out for me what the estimate of reserves was that you had given for the field in that case. Did you find that out?

A. No, I didn't. I had no way of finding that out. I don't have a transcript of that. I can give you the date of the hearing and if you can locate a transcript of it I would be glad to have you read it.

Q. Give me the date of it.

A. I might as well give you all of these while I am on this subject.

Q. We will mark them—

A. They are not in presentable shape.

The Chicago case was in equity 13454, Federal Court, Chicago, Ilinois, July 1934;

The Cities Service case was before the Kansas Corporation Commission in Topeka, Kansas at two different dates, January 1935 and April 1935;

The Chicago case before the Federal Power Commission was in May 1939—that is the one you are familiar with—and there are some other cases. These are cases in Texas. One was called the Shut Down case, Texoma Natural Gas Company versus Terrell, 59 Federal (2) 750, case heard 11-4-32. I furnished some affidavits in that case.

The next case—

Q. Just a minute. What was your estimate of reserves in that case?

A. I don't believe that an estimate of reserves was one of the items under consideration.

Q. What did you testify to in that case about?

A. The Shut Down case—it seems to me that it was largely matters of drainage and effective drainage.

Q. Was there a transcript taken—of course there was if it was in Federal Court. Was this in Federal Court?

A. Yes.

Q. Then a transcript was made.

A. The next one was a Market Demand case, Texoma Natural Gas Company versus Terrell, 2 Fed. Supp. 168, Feb. 3, 1933—hearing on interlocutory injunction. I furnished an affidavit in that case.

Q. For whom?

A. For the Texoma Natural Gas Company.

Q. What was the affidavit?

A. I don't know. These had to do with—

Q. You mean you furnished an affidavit and you don't know what was in that affidavit?

Mr. Keffer: He hasn't said that.

By Mr. March:

Q. What was in the affidavit?
A. I don't remember.

Mr. Keffer: I suggest that the affidavit is th best evidence of what was in it.

By Mr. March:

Q. Was it an estimate of reserves?

Mr. Keffer: Mr. March probably doesn't know, but the Examiner will appreciate that certain of these cases in Federal Court in application of temporary injunction or interlocutory injunction are submitted on affidavit form, not on question and answer form as given here. These affidavits are frequently lengthy and give many details. Certainly I wouldn't want this witness to testify as to what he gave in an affidavit nine years ago.

Mr. Lange: Did that interlocutory proceeding finally result in a hearing on the matter?

Mr. Keffer: I don't think any of those cases ever went beyond the stage of an application for a temporary injunction—wait just a minute. There was first the application for a temporary restraining order in each one of them. I expect that was granted upon the verified bill that was filed. I am supplying some things that I don't remember precisely but I am sure that was the normal case that was taken and these affidavits were submitted on the application for temporary injunction.

Sometimes applications for temporary injunctions and applications for permanent injunctions which could have been two separate transactions, were consolidated in one hearing and I am inclined now to believe they were in those cases, but there was never an appeal from the three judge trial in Federal Court to an appellate court.

Mr. Lange: What I was getting at was where they finally did hear any of the proceedings on the merits they did take the testimony.

Mr. Keffer: I did know that they did in some instances but I am not sure they did in all of the instances. I am

not quite certain. I think one went to the Supreme Court in the Consolidated case where there was testimony taken.

Mr. March: My question is whether or not there was an estimate of reserves given there. I will ask the witness.

Q. Was there an estimate of reserves given there, Mr. Hughes?

The Trial Examiner: If he remembers. Do you remember?

The Witness: I remember this, that if there was an estimate of reserves it wasn't contested in any way. I remember that definitely. In fact, I think in the next one I am coming to there was an estimate of reserves, although the case was against the Railroad Commission. As I remember it they didn't question our estimate of reserves in any way, shape or form. I could be wrong about that.

By Mr. March:

Q. The Railroad Commission didn't question your estimate of reserves?

A. As I remember it.

Q. Did they approve it?

A. I don't know—

Q. You mean you aren't sure?

A. I don't know that they put a stamp of approval on something. I am trying to tell you what happened in this case.

Q. Before we leave the other case, you don't remember whether you had an estimate of reserves in Federal Court?

A. I don't think there was an estimate of reserves of the entire field entered into it in these two last mentioned cases; the cases in Texas, the Shut Down case and the Market Demand case. I don't think that an estimate of reserves of the Texas Railroad Commission entered into those cases. I could be wrong but I am trying my best to remember whether an estimate of reserves came into those cases.

The next case was the Ratable Production case, House Bill No. 266. That was the Texoma Natural Gas Company versus Thompson. Thompson is one of the Railroad Commission's commissioners of Texas. It is in 14 Fed. Supp.

318, 300 U. S. 55, 81 L. E. 510. It says here, "Interlocutory injunction heard 9-19-35; tried 3-31-36."

Mr. Keffer: That was the one I was talking about.

Mr. Lange: And that is the one that preceded your hearing on the merits.

Mr. Keffer: Mr. Hughes has given there the correct style, however, that case was consolidated with a Consolidated Gas Utilities case and went up to the Supreme Court in the Consolidated Gas Utilities versus Thompson. There might be some confusion in the names but the citations will be correct.

By Mr. March:

Q. For whom did you testify in that case?

A. The Texoma and the Consolidated.

Q. Did you have an estimate of reserves in that case?

A. I feel pretty sure that I had an estimate of reserves but I would have to check on that to be positive.

Q. Check that, will you please?

A. I don't know where I can check it until I get home and have a transcript of that made available.

Q. You mean, Mr. Hughes, you don't have a file on your estimate of reserves in the past?

A. I didn't say that I didn't have a file on my estimates of reserves. I can tell you this, that the estimate of reserves I have been using over the past several years back to and including the Cities Service case, couldn't be very far from around 18 or 18½ trillion, which is close to my present 19½ trillion. I can tell you that definitely so if you want to split hairs and know exactly the amount in each one of those cases it can be determined and if I am wrong the record will show it. I am not trying to misrepresent a thing in that statement.

Q. I am not saying that you are. You may proceed.

A. Those are the only ones I have.

Q. I do want to know if you can possibly get from your records what the percentage of drainage was for the Cities Service Company in the Topeka case.

A. I don't remember that I made a study of that. The only way I would know—I remember I made a study of the

reserves, but whether I made a study of the drainage at that time, the only way I could check that would be to obtain a copy of the transcript of that case. At the present time I don't know where I could get it and undoubtedly the Cities Service has it but I don't have it.

Mr. Hughes further testified (Vol. 85, pp. 12699-12721) as follows:

By Mr. March:

Q. I want to ask you if you did arrive at the pay thickness for the entire field?

A. No, definitely not. I think that has been clear in the record.

* * * * *

Q. Now, Mr. Hughes, your recollection was very very vague about the Chicago District pipe line case and I have gone to a lot of trouble to get the transcript of your testimony about it, and I want to ask you a couple of questions about it, and refresh your memory.

A. Which case is that, you say?

Q. That is this case: Chicago District Pipe Line, a corporation, plaintiff, versus Benjamin F. Lienheimer, Andrew Olsen, Charles E. Byer, J. D. Marnane, the persons constituting the Illinois Commerce Commission, and Otto Kerner, Attorney General of the State of Illinois, defendants; U. S. District Court, Northern District of Illinois, Eastern Division, No. 13,454 in equity, Chicago, Illinois, Tuesday, July 17, 1934, 2:30 p. m.—I beg your pardon. Your testimony begins on Wednesday, July 18, 1934, at 10:00 o'clock, a. m.

Now, you were asked this question:

"Q. Have you made a calculation, Mr. Hughes, for the purpose of determining the total amount of natural gas which was in the Texas Panhandle field prior to the beginning of withdrawals from that field?

"A. Yes, I have.

"Q. And what is your judgment in that regard based upon? Is it based upon the total area of the field as we know it?

"A. The information that has been obtained by drilling the various wells in the field.

"Q. What is your estimate?

"A. About 16¾ trillion cubic feet of gas.

"Q. Is that all the gas or the recoverable gas?
"A. That is what I consider recoverable gas."

That is found on Page 1090—Page 1092, rather. Then you state:

"Q. And the recoverable gas which you have given us a figure on is the gas that lies between two rock pressures of 25 and 430 pounds?"

Mr. Keffer: Now, just a moment. Mr. Hughes has never given any testimony in this case as to abandonment pressure. The matters which Mr. March is leading up to are quite definitely that.

Mr. March: No, I am not leading up to that.

Mr. Keffer: Yes, you are.

Mr. March: No, I'm not.

Mr. Keffer: Now, just a moment. Mr. March if he desires, may, of course, give the estimate made by Mr. Hughes as to recoverable gas, but I don't think he has the right on cross examination, at least, to prove by Mr. Hughes what Mr. Hughes might consider to be a proper abandonment pressure.

Mr. March: Mr. Hughes doesn't say anything about abandonment pressure, not a word, and I am not going to say a word about it.

Mr. Keffer: I think it does. I think what you just read could at least be interpreted as that. May it be understood, then, that the data you are reading shall not be considered in connection with any abandonment pressure?

Mr. March: If he doesn't say it. I don't want it to say it. I have no intention of bringing out abandonment pressure.

Mr. Keffer: It is your understanding that what you are reading has nothing to do with abandonment pressure and may not be so considered.

Mr. March: That's satisfactory with me, sure.

Mr. Keffer: All right.

Mr. March: I can't limit what the Examiner will do.

Mr. Keffer: You can make agreements here which are binding upon the Examiner. That's the only thing I want, and if you and I make a stipulation it is binding upon the Examiner, the Power Commission and the courts.

Mr. March: He doesn't mention abandonment pressure here and I am not going to, and as far as I am concerned, it has nothing to do with abandonment pressure.

Mr. Keffer: If it has nothing to do with it, then certainly you can make the stipulation, can't you?

Mr. March: The stipulation is it will not be considered in abandonment pressures?

Mr. Keffer: That's right.

Mr. March: I won't make any kind of stipulation in the record. The testimony will speak for itself. I am not bringing it out in regard to abandonment pressure.

Mr. Keffer: The only point is this, Mr. Examiner, if it is offered from the standpoint of abandonment pressures, an objection to it is good. If it is not offered for that purpose, perhaps the objection is not good.

Now, counsel can clear that up readily. Then if they refuse to do it, then I am going to object to the testimony on the basis that it does have some relevancy to abandonment pressure.

The Trial Examiner: The point is this, I think, that the matter you are referring to there has to do with Mr. Hughes' recovery factor.

Mr. March: It does. That's the point. It has to do with this recovery factor but not abandonment pressure.

Mr. Keffer: And it is limited to that.

Mr. March: That's right. I am not limiting a thing. It doesn't have anything to do with abandonment pressure but it does have to do with the recovery factor.

Mr. Keffer: You said that long ago.

Mr. March: But I am not stipulating with you on anything in the record.

Mr. Keffer: What do you mean? Then you mean you aren't limiting your offer to the recovery factor?

Mr. March: That's all I am bringing out here is in regard to the recovery factor.

Mr. Keffer: And it is offered for that limited purpose?

Mr. March: As far as I am concerned, it is not offered for any other purpose.

Mr. Keffer: As far as you are concerned, you are the only person concerned, because you are offering it.

The Trial Examiner: I think to be proper, Mr. Keffer, I think it is perfectly proper for Mr. March to read there from Mr. Hughes' former testimony if it pertains to Mr. Hughes' recovery factor.

Mr. Keffer: That's right, and it is limited to that.

The Trial Examiner: I don't think it would be proper to go so far as abandonment pressures. Mr. Hughes has not testified in a proceeding which has to do with abandonment pressures.

Mr. March: He doesn't say which one is right on these pressures. He has 100 pounds, 50 pounds, and 25 pounds in a series and I am not trying to confine him down to any abandonment pressures at all.

The Trial Examiner: Well, let's go ahead in the interest of saving time.

Mr. March: Well, then, I will read here to make it complete on Page 1094.

Mr. Keffer: You don't mind me looking here, do you? I have got to see what's coming. I haven't seen this.

Mr. March: No.

Q. You state on Page 1094:

"Q. Will you state how much gas has been withdrawn from the Texas Panhandle field for all purposes from the time of its discovery up to June 1st of this year, 1934?

"A. In round numbers that figure is 4.2 trillion cubic feet.

"The Master: Just about a quarter.

"A. Just about, yes, sir.

"By Mr. Davis:

"Q. That would leave—

"A. That would leave—

"Q. What recoverable gas reserve?

"A. About 12,550,000,000,000 cubic feet in the reservoir."

Q. Now, I ask you if that refreshes your memory in regard to your testimony as to your estimate of reserves in that case.

A. Well, I am assuming that all those figures that you have read were correctly transcribed and you mention there, I believe, 16 and what was that, three-quarters trillion?

Q. Your estimate of reserves that you have here on Page 1090, you state is about 16¾ trillion cubic feet of gas.

A. 16¾ trillion at 25 pounds?

Q. I will read what you stated over here:

"Q. At what rock pressure is it considered that gas is no longer commercially recoverable?

"A. In my figures I use 25 pounds as a point at which it would become uneconomical.

"Q. The recoverable gas which you have given us a figure on is the gas that lies between the two rock pressures of 25 and 430 pounds?

"A. Yes."

A. Yes, that's the point. I wanted to bring it down to the complete basis of the figures that I was mentioning from memory the other day which would be around 18 trillion. I was trying to refresh my memory as to about what that 16¾ trillion at 25 pounds abandonment pressure was on the comparable basis that I generally talk of and the total original reserves in place down to zero bottom hole, and that figure, as nearly as I can compute it rapidly here with the slide rule, would be slightly over 18 trillion.

Q. At zero pounds?

A. Yes, at zero pounds bottom hole. Now, what else was it you wanted to know about that?

Q. I want to know now why you considered that you had taken care of the recovery factor when you went down to 25 pounds and did not apply a 90 per cent recovery factor.

A. Well, of course, 25 pounds abandonment pressure has nothing to do with our consideration of the recovery factor. That is quite definite in the first place, and in the second place, as I remember it, that was the first, or very nearly the first time in which I had attempted to make an estimate

of reserves of the entire field in the Panhandle, and I have certainly learned a lot since then.

At that time I didn't know that a lot of these wells were going to go dead from water conditions and be abandoned, many of them at above 100 pounds and some of them as high as 200 pounds. There are many many things that I did not know about the field at that time that I do know about the field at this itme. In fact, I hadn't even noticed the fact that in computing down to 25 pounds abandonment the very arithmetic of that computation in the light of what I know now was incorrect, and that has been brought out in this record. It was an obvious error at that time and I admit it.

Q. Now, you use the words "recoverable gas reserves" as 12,550,000,000,000, so you apparently assume that all the gas could be recovered?

A. The explanation I just made was on that very question that you have just now asked.

Q. All right, sir. Then you state on Page 1148—no, on Page 1147:

"Q. Have you an opinion, Mr. Hughes, on the basis of the facts which are now known to you on the Texas Panhandle field as to the probable remaining life of that field as a natural gas field at this time?

"A. Based on the estimates I mentioned previously and in particular the more conservative estimate on 1936 withdrawals, it points to a life of about $11\frac{1}{2}$ years from the present time.",

Do you recall that statement?

A. I recall something of that, and I remember as I recall it, at that time the production from the field for stripping purposes was increasing by leaps and bounds.

Now, you read a statement that refers to the more conservative estimate for 1936. Without going back I would want to check that, but I think that at that time I projected the trend in the rate of increase in production from the field that was taking place at that moment and it continued to take place for quite a while after that hearing that you are reading from, so that quite definitely that statement was made in view of the existing conditions at that time and I am making that statement from memory and I am quite confident that that can be confirmed.

Q. Do you think the gas will be exhausted in eleven and a half years from 1934?

A. Well, all I need to do in connection with that is that at the time we were considering this very very great increase in the rate of production from that field, as I said before, that increase did continue for quite a few months, but then the law was passed in which this stripping of the sweet gas was made, was stopped, and the trend of production changed quite abruptly as is shown and definitely shown in the graph of annual production in Mr. Peterson's exhibit, so that graph explains exactly what my explanation is as to that. Of course the arithmetic at that date on given reserves and with an increased rate of production that was taking place at that time applied to the reserve, the arithmetic ended up with so many years. When that rate changed quite abruptly the arithmetic would be something else.

Q. Well, now, Mr. Hughes, I will refresh your memory on what you said would be the withdrawals for 1935. On Page 1134 of the transcript:

"Q. Have you made an estimate of the probable withdrawals of gas from the field for all purposes in 1935?

"A. I have.

"Q. What is your judgment?

"A. I have made two estimates on that. One is based year's activities which leads me to a figure which I do not think is out of line which would be an average daily withdrawal of 3,400,000,000, but the figure which I think is more conservative, although it is not necessarily more accurate, would be to take what happened during the past two years and let that be the guide, and that arrives at a figure of 3,060,000,000 cubic feet daily which would be a yearly withdrawal of 1,120,000,000,000."

Now, what were the withdrawals in 1935?

A. I don't know, but they are in evidence here and I think what you have just read explains what I had tried to recall from memory as to what that arithmetic involved. I am assuming that you are reading it, and I am assuming it was transcribed correctly.

Q. Now, I find here that—and which has been of great interest to me—that you gave an estimate of reserves according to your own statement here and I will read it to you, in 1932. On direct examination on Page 1087 you say this:

"Q. Are you the same Mr. C. Don Hughes who testified in 1932 before the Illinois Commission in a case involving the Peoples Gas, Light and Coke Company?

"A. I am."

And on over further here there is a statement that you didn't make an estimate of reserves. Is that correct?

A. A statement that I did or did not?

Q. That you did.

A. If it is in there it must be correct.

Q. Did you make an estimate of reserves in 1932?

A. I don't know. That could be determined. From my memory I didn't remember that I did. I may have. If I did, I did. I haven't tried to miscolor whether I did or not.

Q. All right, now, I have gone through this testimony and I have tried to find out what method you employed, and I can't do it, and I want you to see if you can throw any light upon it.

On Page—that is, in 1934—on Page 1176:

"Q. How did you determine what was originally in the field?

"A. Well, it is a long process. The rock pressures and thickness and pay saturations and porosity figures—I don't have any details of that with me. It varies from one part of the field to another and I try to go into the details of that sort of thing, and to try to go into the details of that sort of a thing, we would have to treat practically every area in the field separately."

Now, what method does that say? What is that method?

A. I think it says—I am not going to try to answer questions on that early stuff. I would have to refer to any reports that I may have had at that time. I have tried to give you a sort of a chronological picture of how my method was arrived at in the first place and how I have gone along from year to year, and some of those details at the different stages in which I was working, I don't know that I could even tell very specifically what they were at (illegible) different stages. I think that pretty well explains what was done. To go back of that to try to find the details, I wouldn't attempt to do here. I don't think it means anything, anyway.

Q. All right, sir. This is the only transcript I have been able to get ahold of. Now, of course, a trillion or so doesn't make much difference when you are estimating reserves, does it—a mistake of a trillion or so?

A. A mistake?

Q. Yes, a trillion or so when you are estimating reserves. Like you have an edition of your estimate coming out in 1932 and 1934 and 1939 and 1941 and 1945 and they are all different.

A. Assuming they would be different in 1941 and 1945.

Q. Well, in view of the fact they have been different in the past, I assume you will continue that in estimating reserves.

A. I told you when the conditions in the field at the date of the estimate shows that it is reasonable and practical to do so, I am constantly differing. I have made no attempt to show that the contrary was true.

Q. Now, this is one time I want to get in and—right now —and I don't think it advisable to wait until this other exhibit comes up.

Don't go into detail, but state just how you applied the pressure decline method to get that .9 factor. Now, there was something said about another exhibit which you had which brought that out very clearly. I want you to state in regard to this exhibit briefly how that was arrived at.

Mr. Spencer: Mr. Examiner, unless I am badly mistaken, I think Mr. Hughes had explained that at least a dozen times how he arrived at his factor.

Mr. March: No, he didn't explain how he arrived at— the last time, in how he arrived at it and how he checked against his pressure decline method. I started to have him do it and Mr. Keffer said he had another exhibit on that and he would wait to have him do it. I want him to do it right now. I don't want to take any chances on that other exhibit.

The Trial Examiner: Let us do this, Mr. March: As I recall it, that particular matter came up and you made a reservation at that time and it seems to me if an exhibit— future exhibit, is to come in that deals with that particular matter, it would be repetitious to go into it here now and then again on the other exhibit.

Q. Is there another exhibit, Mr. Hughes?

Mr. Spencer: Let me answer that, Mr. March.

Mr. March: All right.

Mr. Spencer: I will make this stipulation with you, Mr. March: Mr. Hughes will have an exhibit of that character which we will submit here, or he will be permitted to be cross examined on the subject.

Mr. March: All right. I just didn't want to let that slip away.

Now, I want to ask you just a couple more questions.

Q. As I understand, you used Mr. Peterson's estimate of withdrawals?

A. Yes, that's right. I used his table of withdrawals.

Q. All right, sir. Now, in averaging your pressures for various zones, did you average in the dry holes?

A. How's that?

Q. I said, in averaging your average pressures for each of your pressure bands, did you average in dry holes? In other words, when you got to a dry hole in a pressure band, did you say "Zero"?

A. You mean my zone map? My potentials?

Q. Yes, did you average in your dry holes, the open flow at the dry holes in getting your average open flows?

A. Well, I'll tell you, I took into account the dry holes. Those dry holes are what caused me to originally not include as much of an area in my outline of the field as the Railroad Commission includes.

Q. I understand.

A. So they were automatically in that in my idea of what those marginal areas would do. Now, any dry holes that have been drilled within the different zones since the time that I concluded that I had a reasonable figure representing the average of those zones has not gone into it for the same reason that I explained the other day why some of those inflated potentials in the other direction did not go into my average for a given zone.

Q. So in averaging your pressures in the—

A. Potentials, are you talking about?

Q. Potentials, yes—open flows.

In averaging your open flows in your various zones you did not average in your dry holes?

A. I have explained that.

Q. Did you? I'll make this very simple. You see up here on this map Moore County?

A. Yes.

Q. You see that red band there?

A. Yes.

Q. That red pressure band?

A. Yes.

Q. I want to know in getting your average open flows for the red band whether or not you averaged in all of the dry holes as zero?

A. Well, if those dry holes existed and were in that band at the time I was arriving at my average, very likely they were in. However, dry holes that have come in since I decided that I had a good average to use, wouldn't go into them.

Q. I see. So in every one of these bands—

A. Of course, in a red area there aren't very many dry holes. Dry holes in the red area are very very much the exception. Of course there are some. I see here some dry holes in that area in the red up there that you were asking me about right near those Ingerton wells here we were talking about the other day. I don't think I pointed them out at that time but this map shows that in what I called the red area within a mile and a half of that Ingerton well, there are about four dry holes.

Q. You averaged all of those in?

A. That would show that my treatment of that area and the color that I show is certainly very very reasonable, even though the one well might be pointed out as being a little higher than the average color band indicates.

Q. Now, if you average in the dry holes in the red area, did you average them in in all of the open flow bands as you came to them?

A. Well, I have tried to explain to you what I must have done. If those dry holes had existed, that is, had been drilled at the time that I was getting the information on my averages I would probably have used them. However, I want to show further that within any of the zones, getting up into the high value acreage, there are not very many dry holes.

Theoretically there shouldn't be any, but in actual practice they do drill them once in a while.

Mr. Hughes further testified on cross examination (Vol. 90, pp. 13842-13846) as follows:

Q. Did you prepare this exhibit since you have been in Denver, Colorado?

A. The part that has to do with Mr. Hammer obviously was because I never heard of his information until I came up here. The other part, as I said, has been growing for a number of years. The first year that the Railroad Commission of Texas gave us a weighted average pressure I tried the pressure decline method. It gave me a figure that was obviously too high and ever since then—every time they bring a figure out I again apply it and I find that the things are changing and you can't get consistent results and the first part of my exhibit is a definite explanation of what that study results in.

Q. You make one of the strangest statements I ever heard of over here on the first page of your statement—on page 20. You make this statement:

"An extension of this trend points to an Original Reserve of 16.3 trillion for the field. If this is correct, then my estimate of approximately 19¼ trillion is too high. Even though this is the indication, I am inclined to stand on the evidence that 19¼ is a reasonable figure and that the manner in which I arrived at it is reasonable."

Now I want to ask you this question: How could a figure of 19¼ trillion be reasonable when you say that everything points to a reserve of four trillion less than that?

A. Well, I didn't say that everything points to it. I am at that point discussing the extension of a trend which has been going on for five years, very consistently in the Texas Panhandle and that has a bearing on what I was talking about a moment ago. I am definitely interested in knowing what is going on in that reservoir. I want to know how it is performing from year to year and in order to do that I construct these curves which are critical as to the method of showing what is going on, and I have found that from year to year at each new period that we have a survey that we are finding that the field is actually performing by producing less amount per pound drop than it had been before.

Now, I can't shut my eyes to that trend. Now, I don't know that it is going to continue, but I am saying in this

statement that if that trend continues in a straight line, and you will see by referring to Chart C that it is a fairly straight line—now if that trend continues down to the end of the life of the field, it means that the field has 16.3 trillion in it.

Now, I am not convinced that that trend is going to continue. I have already arrived in other manners at an estimate of 19¼ trillion which is a figure that is higher than the one I have just quoted.

Q. 16.3 trillion—if it could—16.3 trillion and 19¼ trillion couldn't be right at the same time. One of them has got to be wrong. Now which horse are you going to ride?

A. I am watching the trend of events. The longer this situation continues to exist that has been existing for the past five years, the more convinced and the more confidence I have in the trend as shown on Chart C.

Q. Are you trying to say that the reserves are somewhere between 16.3 trillion and 19¼ trillion?

A. No, not at this point, but if that trend continues that is apt to be my conclusion a little later on down the line. For the present I am willing to stand on the 19¼.

Q. You may change your estimate at any time within four trillion?

A. When the information that is the most pertinent in the field shows that I need to revise my figure I will revise it.

Q. Just as you have done in the past.

A. Yes, sir.

Q. You have revised it upwards from 16.3 trillion since 1934.

A. 16.3—I believe you will recall that that was on a 25 pound abandonment and I converted it the day you brought that figure in, and that figure is about 18 trillion; so let's forget that 16.3. I have revised it from 18 trillion to 19¼ trillion.

Q. You did testify that the reserves will only last eleven years from 1934.

A. I think that was very definitely explained in the light of what was going on at a certain time. The arithmetic showed a certain figure.

Q. Every time you make your calculations the arithmetic shows a different figure, doesn't it?

A. As to what?

Q. You had a calculation last year where your arithmetic shows one figure for reserves and you make one this year that shows another figure for the reserves.

A. We were talking about the arithmetic on the life of the field. Now what kind of arithmetic are you talking about?

Q. Every time you have made an estimate of the life of the reserves of the Texas Panhandle Field it has been different, hasn't it?

A. Not every time. I have just about decided that in the light of some of these things that are taking place in the reservoir that have to do with these decline studies that there is not much use to keep changing these figures just a small amount until enough evidence piles up that it should be changed materially, and I have brought out—I have stated quite carefully in this particular case that the figure that I am using today is the same figure I used in Chicago in 1939, but that the tendency of the performance—the conditions that prevail in the field today would allow me to revise that slightly downward, but again I am waiting for more evidence to build up showing that an appreciable change should be made. It might tend to conform to the one I am using.

Q. How long do you think it will be before anybody can tell what the reserves of the Panhandle Field are, approximately?

A. Well, nobody will ever know what the reserves were until the last cubic foot, or approximately, has been produced.

Mr. Hughes further testified on cross examination (Vol. 91, pp. 13880-13885) as follows:

Q. Now, you made a great many statements here about the equalized pressure or the equilibrium pressure, which I believe is what you called it. You stated here on Page 17: "I believe the declines as a whole have been in richer than average areas and if the entire field were shut in today until the pressures became equalized, the final pressure would be less in pounds than our present so-called weighted average pressure."

Were you referring there to the weighted average pressure of the Railroad Commission of Texas?

A. Yes.

Q. You were not referring to Mr. Hammer's weighted average pressure?

A. It wouldn't make any difference. I don't see much difference between his and theirs as to the different dates. One date in particular is a little different. The weighted average pressure arrived at by weighting is the weighted ~~average~~ I am talking about, and at the time this was written I hadn't seen his figures so I was obviously referring to the Railroad Commission's pressure.

Q. This exhibit was prepared in rebuttal to Mr. Hammer's exhibit, wasn't it?

A. I told you yesterday the last part of the exhibit was; the first part was a study I made long before I heard of Mr. Hammer's exhibit.

Q. When was the first part prepared?

A. Well, I don't even know for sure.

Q. When did you have the first part typed up?

A. When was it typed up?

Q. Yes.

A. I don't know. I might be able to check back and give you the exact date.

Q. Has it been since you have been here in Denver?

A. This particular typing of it, yes.

Q. Here is what disturbs me: "The final pressure would be less in pounds than our present so-called weighted average pressure." Now, do you know what the equilibrium pressure would be if the field were shut in and allowed to equalize?

A. No, I don't, I'm sorry to state, and I don't think anybody knows for sure what it would be, but I am quite positive it would be something less than the figure that we arrived at by weighting the field by acreage only.

What page are you reading from?

Q. Page 17. If you don't know what the equilibrium pressure will be, how can you come up here and say it will be less than the weighted average pressure?

A. I am not quite sure it will be less.

Q. How do you know?

A. In my opinion I don't think there is any doubt but what this is true that the great bulk of the withdrawals and the pressure losses throughout the field have taken place in richer than average areas. The greatest portion of the

field today that remains at high pressures is very lean, so if you would shut the field in today, shut all of the wells in today and allow equilibrium to take place, those high pressure and lean areas would attempt by migration to build that pressure up. As that lean amount of gas migrated over into the low pressure areas which have larger content, they wouldn't fill it up quite as much in proportion as to what they are losing; so you finally would arrive at an equilibrium pressure that wouldn't be as great as this weighted average pressure we arrive at when we weight it on the acreage alone.

Q. How much less would it be?

A. I don't know.

Q. You don't have any idea?

A. I don't know how much less it would be.

Q. You haven't given it any consideration as to whether it would be a hundred pounds less or ten pounds less?

A. I haven't made any estimate of what it might be for the reasons that I have explained which are good sound geological reasons. I am quite sure it would be less than the weighted average pressure arrived at today on acreage.

Q. Why haven't you made some effort to ascertain how much less it would be?

A. I don't think—

Q. It couldn't be too much less, could it?

A. What do you mean, too much less?

Q. I mean by that, it couldn't be very many pounds less of the weighted average pressure of the field.

A. That wouldn't have anything to do with it. The facts that I have explained could allow quite a great variation between the finally arrived at equilibrium pressure and to-day's weighted average pressure. It could be quite a sizeable amount, in my opinion.

Q. It is one of the relevant things of yours that can't be measured or appraised?

A. I haven't attempted to measure it. The conditions I have described are present in the field and the decisions following the observations of those conditions would lead quite definitely to the conclusion that that equilibrium pressure would be less than the weighted average pressure.

Q. Now, Mr. Hughes, since you have such a thorough knowledge of everything that has happened in the field, will you tell us this: How long would it take us, approximately,

if the field were shut in tomorrow when the equilibrium pressure would be reached?

A. I haven't any idea.

Q. I thought you studied the movement of gas and the obstacles of the movement of gas together. Do you have any idea as to how long it would take to reach 100 per cent equilibrium?

A. It would take a long time.

Q. A hundred years?

A. It would take a very long time.

Q. A very long time?

A. Yes.

Q. What does a long time mean to you?

A. We would be dead and gone before it reached that equilibrium pressure.

* * * * *

And again (pp. 13911-13915, Vol. 91.)

Q. Do you know of any field as large as the Panhandle field of Texas where the pressure decline method has been applied where the pressure pound and production didn't vary from year to year but didn't average out on a straight line?

A. Well, the first thought on that question is that I don't know of any other field in the world that is as large as the Panhandle field with respect to its reserves. I do know of a field that has more acres in it, but now to come to the second part of your question—

Q. What field has more acres?

A. The Hugoton field.

Q. Right north of this Panhandle field?

A. Yes, that is north.

Now, with respect to the second part of your question, the only way you can answer that is by making studies of the fields. Whether they do or not can only be determined by studying the field and when you study the field if they do give consistent results you conclude that you can apply Boyle's Law—I mean the pressure decline method—and in studying the field if you find that it does not give consistent results from time to time you either conclude that the whole thing is worthless and throw it out the window, or if it goes along consistently and shows from one period to the next

over a consistent number of periods that there is a trend being established, then I think you are at liberty to take into account the trend that is being exhibited and interpret your answers in the light of the trend.

Q. I notice in this rebuttal exhibit that you stay away from the part of Mr. Hammer's exhibit where he makes his estimate of the recoverable reserves of the Canadian River Gas Company. In other words, you don't have any rebuttal to that. You just take his figures on the whole field.

Now, I will ask you this question: I will ask you the question as to whether or not you have plotted production against pressure decline utilizing his figures just on the Canadian River part of his estimate.

A. Let me see. Will you restate that?

Q. I want to know whether or not you have utilized his figures and have plotted the production versus the pressure decline on the Canadian River part of his estimate.

A. You mean by that on the Canadian River acreage or on the quadrants in the Canadian River—

Q. First on the Canadian River acreage.

A. Well, I couldn't find in his working sheets the figures that would have permitted me to do that, so the answer to that portion of it is no.

Now whether I have plotted the comparable study on his quadrants which contain some Canadian River acreage, I don't know. I would have to refer to my work sheets on what I have done with his figures before I could answer that question.

Q. Have you ever plotted the production of the Canadian River wells against the pressure drops of the Canadian River wells through the year 1940 to ascertain whether or not they do not approach a straight line?

A. Well, I am quite sure that I haven't done that.

Q. You haven't done it, so you wouldn't—

A. Through 1940.

Q. Yes. You wouldn't know whether or not that reveals a straight line or not. You wouldn't know whether it would approach a straight line?

A. A straight line with respect to what?

Q. Similar to this Chart C-1. In other words, taking the

example to the left there and plotting your production against your pressure decline through 1940 on Canadian River wells.

A. Oh, you mean just on the wells alone?

Q. Yes, production from the wells and pressure decline from Canadian River's own wells.

A. And on each well, just production on each well?

Q. Total production decline versus pressure decline.

A. Well, how would you arrive at the pressure decline? I want to know for sure what it is you are asking me.

Q. I am asking you if you ever plotted the Canadian River well production against the Canadian River pressure decline similar to the way that you have plotted the production and pressure declines for the whole field on this Chart C-1 in the left-hand diagram.

A. Well, if you mean plotting the grand total of Canadian River production against the arithmetical average pressures of the wells, that is of a given date and new wells that come in and just bring them into the picture and all that, you mean?

Q. I mean this: You know how you did this in Column No. 1 there?

A. Yes.

Q. I mean doing it just like you did that.

A. No, I haven't.

Hughes further testified on cross examination (Vol. 94, pp. 14490-14499) as follows:

Q. Now, Mr. Hughes, your next move here, as you say, is to assign an open flow to each one of your sections. That's right, isn't it?

A. That's right.

Q. By an open flow do you mean what the open flow would be at virgin pressure conditions?

A. That's my interpretation and in fact my intention, and since these open flows that went into the study that I have made on Canadian River Gas Company were most carefully carried back by them to virgin pressure conditions, they are more nearly actual virgin pressure conditions than I have heretofore used and as I have explained before—

Q. All right, in assigning the open flow to each section, did you, where there were wells in the section, take the

arithmetical average of the various open flows of the various wells in the section?

A. I don't think I did. In fact, I can't think of very many sections that actually have more than one well in them. There are a few cases in some of those sections I believe that the tracts were treated separately so that it would not necessarily be an arithmetical average. Whether or not I did that would have depended upon the location of those wells in the section, the geological conditions in the area. There are a number of things that went into my consideration of a given tract before the actual open flow figure was determined.

Q. Now, so there we likewise differ from the way you worked your field as a whole. You didn't take the field as a whole, you took the average open flows within your various pressure bands, pretty well, didn't you?

A. From the pressure bands. I averaged the open flow for the zone.

Q. Zone, that's what I mean.

A. Yes.

Q. Now, in the case of the section, though, you don't do that. You approximate what the open flow should be based upon these various wells, where there are wells in the section.

A. Well, I said that I don't remember taking the arithmetical average. Now, in the first place let's come back and see about how many cases there would be. I don't suppose there would be over—oh, a dozen sections in the whole area that have more than one well in the given section. I am just looking very roughly and hurriedly. I don't want to be pinned down to that dozen, either, but in so far as to the acreage that I am dealing with—this what I am talking about is incidental and if there were more than one well in a given section, the information on both wells we would use.

Now, if you want to get specific on some section, why, I might be able to tell you whether it is an arithmetical average of the potentials. I don't remember. I can't remember whether it was or not. I could tell you this: It wouldn't need to be—for instance, if you have a section of land with two wells down on one side of it that were pretty good sized wells and immediately on the north line in the next section was a

very very small well, naturally I wouldn't appraise that section that had those two good wells down along the south line according to the potential arithmetical potential of those two wells. I would let the small well along the north line have a bearing on the classification that I would assign to that section.

Q. Without going into the thing in detail, you know quite well, do you not, you didn't take the arithmetical averages?

A. I don't believe that it would work out that I did, but I am telling you what was involved in whatever I took.

Q. Don't you know what you did in this case? We have to surmise what you did?

A. I think I have described the procedure that I would go through in appraising a section.

Q. When did you go through all this procedure in estimating the Canadian River acreage?

A. I don't remember exactly.

Q. It has been since you came to Denver, hasn't it?

A. No, my goodness!

Q. When?

A. I don't remember.

Q. Don't you know whether it was in 1940 or in 1939?

A. Well, I told you the date of the map. The exhibit, Exhibit No. 212, is dated the first of 1939; I told you a field-wide section by section survey would be a year later. That would be the first of 1940, wouldn't it?

Q. Yes.

A. I would assume the details on this Canadian River were probably worked out about a year ago on that basis. In trying to reconstruct here what took place, I am trying to give you just what did take place.

Q. In some cases you are not quite sure yourself just what did take place?

A. Well, I have described the procedure.

Mr. Spencer: He is not able to tell you the results section by section, Mr. March.

By Mr. March:

Q. Now, Mr. Hughes, when you came to a section where there was a well right in the middle of it, did you assign the open flow of that well to the section?

A. Again I cannot remember, but let me tell you the line of reasoning I would have used in a case like that. Had that well that was in the middle of a section been greatly different from the sizes of wells immediately around that section, if that were true I certainly would not have assigned the value of that one well. If I had it would have been due to conditions that I considered making it representative.

Under the set of conditions I have described, I have tried to picture a situation that would fit a case where according to my procedure I would not have given it a figure. Again I don't remember all of the different ones. You have 13 pages in my working sheets, as I remember it, and each one of those pages have about 40 entries on each page, so there must be approximately 400 entries.

Q. In other words, you have 400 individual estimates of reserves on your working papers, haven't you?

A. They are estimates on reserves based upon the figure which I have just given you on approximately 400 tracts of land.

Q. In other words, what you are doing is taking one little old tract of land, an arbitrary section, and estimating the reserves for it and then adding them all up to get the total?

A. Taking it arbitrarily?

Q. Well, naturally you didn't have anything to do—

The Trial Examiner: He told you, Mr. March, that he has taken them section by section. It is quite clear in the record.

Mr. March: Yes, I think it is quite clear, too, that he has made 400 individual estimates of reserves.

Q. You have estimated the reserves on each of the tracts, haven't you?

A. There is an estimate of reserves on each tract.

Q. That is right. Mr. Hughes, do you think you could tell anything about the reserves of a given tract of land by taking that one tract and making an estimate of reserves for it? Do you think you could get a correct reserve on the one tract of land?

A. If I didn't think I was getting a correct picture, I

certainly wouldn't have been spending these years doing that in the Panhandle field. My clients must have been thinking I have been doing it or they wouldn't have been paying me all these years to keep doing it.

Q. Then you wouldn't criticise Mr. Hammer in so far as attempting to estimate Canadian River reserves by just taking the quadrants the Canadian River reserves are in? In case you did disagree with his method of averaging in so far as attempting to estimate reserves for the Canadian River acreage alone, you wouldn't criticise him for attempting to do that, would you?

A. Apparently I have criticised him indirectly in that I didn't do it. I wanted to get down to smaller tracts in treating the Canadian River leases.

Mr. Spencer: I think you misunderstood his question, Mr. Hughes.

By Mr. March:

Q. The point I am stating here is, Mr. Hammer took in estimating the reserves the quadrant in which the Canadian River had acreage as some of the acreage owned there was owned by other companies. You would not criticise him for limiting his estimate of Canadian River reserves to that area in view of the fact you have taken smaller areas and estimated Canadian River reserves, would you?

Mr. Spencer: Mr. March, I don't want to interrupt your cross examination—I want to help you—but as I understand your question, it is "you wouldn't criticise Mr. Hammer for estimating reserves based upon his quadrants, when you have gone much further in using a much smaller unit in which to estimate it." Is that the point you have in mind?

Mr. March: In view of the fact he estimates reserves for smaller units or whether he would criticise Mr. Hammer for using the Canadian River quadrants for the Canadian River Gas Company and not take the whole field into consideration. That is what I have in mind.

Mr. Spencer: You are talking about gas in place?

Mr. March: No, I am not talking about gas in place but I am talking about recoverable gas. I want to have it understood that I am talking about recoverable gas.

~~Mr. Spencer: I would like to have it understood that I want the question to be clear as to what he is answering.~~

By Mr. March:

Q. Do you understand my question?

A. I think it is a pretty difficult question to answer.

Q. It is obviously in the record that you have taken smaller units than Mr. Hammer thought of. So much for that step.

Then you multiply your acreage in each section by the potential which you have allocated, do you not?

A. That is right.

Q. In that respect you do just as you did before in your other estimate in so far as that particular step is concerned?

A. Yes, that step is the same.

Q. Then you do the same. So much for that step.

Then you would go a step further. You then do what?

A. Well, for convenience, on the working papers that I have set out there are the additional steps that carry this on through, making an estimate of remaining reserves at different dates that are involved. At that point that step we have just finished where we have multiplied acres by potential, at that point we can multiply that product acre by potential by my factor .92 and that gives me the estimated original reserves of gas.

Q. Yes, but you don't do that as you have pressure which comes in there.

A. No. I want to point out to you that I do that. If you go down to the bottom; that is, the sum of all of those acres times potential products on the last page, you will see a grand total figure which is referred to in my written statement. That grand total figure is multiplied by my factor .92 which gives me directly my estimate of original reserves in the Canadian River acreage.

Q. Why do you have pressure involved over here after you multiply your acres by potential? You say that the pressure factor in the left-hand column on the first well is indicated as 425 pounds at .9873.

A. I just explained to you—apparently you weren't

listening—that these next steps you are going to point to have to do with estimation of reserves at later dates. I also want to point out that at the end of this step just made in taking these grand totals here on the last page times the potential you will find a figure which I have referred to in my written statement to which I applied my .919211 factor which gives me without going into pressures or anything, and without referring to these columns on these working sheets, I have a figure that gives me my estimate of original reserves of the Canadian River Gas Company leases.

Mr. Spencer: At zero wellhead.

The Witness: At zero wellhead—at zero bottom hole. At that stage I have my estimate of original reserves. What you are stating has to do with something else and—

Hughes also testified on cross examination (Vol. 94, pp. 14502-14508) as follows:

Q. When you brought pressures to bear here in the Canadian River estimates of the remaining reserves as of 1932, you brought into play the pressure decline method which you condemn, don't you?

A. I brought it into play in a manner which I thought and which I consider that some of it, not working in the field as a whole, had been ironed out in that I have attempted to classify acreage according to volume. That was the reason I classified my acreage in accordance with potentials.

Q. You are now saying that the pressure decline method will work in estimating the remaining reserves of the Canadian River acreage?

A. Well, that's the way I have applied it, yes.

Q. And that is your position?

A. It has been my position all along that the pressure decline method should work if we weight the field, and if we know the correct manner of applying it in accordance with volume. My open flow classification of the tract by tract study of Canadian River acreage is my opinion as to the closest approximation on a volume basis. Now, there are some things, however, going on in the Texas Panhandle field that as time goes on and as we study them, and if it continues, why, they may be well recognized that the pressure

decline method is not even working, assuming we did have that weighted volume.

Q. You mean it is—

A. So that that is getting into something else that—

Q. It may be that it will not even be working in the Canadian River acreage as you apply the method to the Canadian River acreage?

A. Well, if it isn't working in the manner that I have applied it, the other method that would be working if these studies lead to the fact that there is another situation that is causing it to work otherwise, it will certainly show that Canadian River has been suffering a whole lot more drainage than this study shows, quite definitely.

Q. How could the pressure decline method show anything if it wasn't working?

A. Well, I have explained I am assuming that it is working in this particular study.

Q. In this particular study?

A. But I am telling you what would be the result if it is not working in the manner that I am assuming it, but if it is working in the manner that fits in with this study that I am making currently, it is a method that I am not ready to sponsor. It is a well-known and well-recognized relationship but I am not willing to sponsor that application to the Panhandle field, but if it is working, if it turns out a few years from now that it has been working in that manner all along, I have terribly underestimated the amount of loss by drainage from Canadian River acreage and I know that very definitely.

Q. You say you are experimenting on that method now?

A. I am not experimenting on it. I am merely watching it. I am watching the performance of the field. At the present date it indicates that the field is working under that method but I am not willing to agree as yet that it is because I want a little more history to prove it, but the history for the past five years has definitely indicated that there is something going on down there that would fit in with this other method and it is the method that Mr. Gill referred to the other day and as I said before—

Q. By the way, you might just tell us how that method differs from all three of these other methods—of these other two methods.

A. Well, it is very simple in that we have been assuming all along that the Texas Panhandle reservoir was under 100 per cent volumetric control, and in a reservoir which is under volumetric control, Boyle's Law works in such a manner that the remaining reserves in the field are always directly proportional to the remaining pressures in the field.

Now, the thing that I am talking about is a reservoir that is under capillary control and a reservoir under capillary control as it so works out, the remaining reserve in the field varies directly as the squares of the remaining pressure at the time, and it is quite a different arrangement. It would involve an entirely different manner of computing this drainage in this study I have made. It is a well-recognized method. There is no question about that, but I can tell you very definitely that if that method which applies to reservoirs under capillary control is working in the Texas Panhandle field, I can repeat again I have very grossly underestimated the amount of drainage that the Canadian River acreage has been suffering.

Q. I notice here in working your pressure decline method the new thing here strikes me is that instead of using pressure and production, you have left production clear out of it and use your—what, in place of production?

A. Well, here is the only thing: You are trying to tie this in with production. Most of those leases have never had any well on them and there is no production that you can put up, alongside of the pressure drop in each one of those tracts. What I have done, I have estimated the content of each one of those tracts and at the various dates depending upon the pressures existing on those tracts, I have applied Boyle's Law to arrive at the remaining estimated reserves of those tracts. It is very simple what I have done. It is a simple application of Boyle's law, tract by tract.

Q. Nominally, application of Boyle's law would bring your production to bear, wouldn't it?

A. You are talking about the pressure decline method and I am talking about an application of Boyle's law based upon the estimate of reserves that I estimated was originally in each tract.

Q. How does Boyle's law differ from the pressure decline method?

A. Well, that was explained at length the other day.

Q. By Mr. Gill, but I want you to explain it.

A. I explained it.

Q. You did?

A. I did, at length.

Q. All right. Now, you get a product which is considerably lower, which is some lower than the product—your original reserve figure. For example, in this first one here I see you get a product—just a moment here—the first product I see is 632 there as of 1932. What is your original reserve there in that first illustration?

A. Well, these figures haven't been as to each tract by tract—have not been converted to reserves. The product that you are pointing to as the product of acres times MMcF. under the 1932 period is 632 compared with an original acre times MMcF. product under virgin pressure conditions of 640.

Q. Using in the latter case, of course, your pressures?

A. That's right. The pressure in that particular tract had gone down from 430 to 425 and that difference between 640 and 632 is an expression of the difference between 430 pounds virgin wellhead pressure corrected down to reservoir pressure, and 425 pounds remaining pressure at 1932 corrected down to reservoir pressure.

Q. Now, Mr. Hughes, is there any way that I could compare your original reserve for each section to your remaining reserves as of 1932, 1938 and 1939, for each section? Have you got a calculation showing that?

A. These are the basic figures that we are pointing to. All you would need to do with each one of these figures under the tract would be to take that product which is acre times MMcF. and multiply it by my conversion factor of .919211. That would convert each one of those acres times MMcF. products into my estimate of gas in place at zero bottom hole.

The additional method of estimating reserves which Hughes referred to in his cross examination, supra (pp. 14504-14505) was incorporated in Exhibit 315. This exhibit was offered in evidence, which offer was rejected by the Examiner and exception taken, as shown by the following pages of the Record, Vol. 102, pp. 15871-15876:

By Mr. Keffer:

Q. You are the same C. Don Hughes who has testified before in this case, are you not?

A. Yes, I am.

Q. And you have been sworn?

A. Yes.

Q. Mr. Hughes, you have prepared a written statement with respect to some further testimony on reserves in the field, have you not?

A. Yes.

Mr. March: Now, Mr. Examiner—

Trial Examiner: (interposing) Just a moment.

By Mr. Keffer:

Q. Is this the instrument?

A. Yes, it is.

Mr. Keffer: May this instrument be marked?

Trial Examiner: Mark the document referred to by the Witness Hughes for identification as Exhibit 315.

(Exhibit 315, Witness Hughes, marked for identification.)

Mr. March: Mr. Examiner, we strenuously object to any further testimony at this late date in regard to gas reserves. Obviously, this will reopen the whole question of gas reserves. I would like to direct the Examiner's attention to this, that during the last five months, Respondents had every opportunity to come in here and bring on geologists and present estimates of reserves and give other reserve testimony. Not only that, but they were given adequate opportunity before we recessed in Denver to do that and this hearing was convened for the specific purpose of taking the testimony of Christy Payne and Mr. Lerch.

As a matter of fact, the whole thing that prompted this additional hearing in Washington was the application to take the depositions of Christy Payne and F. H. Lerch, Jr. Now, I want to refer the Examiner to that application and it states very specifically there that matters would be limited to that testimony of F. H. Lerch and Christy Payne.

To bring this testimony in here will reopen the hearing

on reserves. It will bring into play new issues. It will otherwise continue this hearing indefinitely and I think any court of law in this country would rule that the respondents have certainly had, in five months, adequate opportunity to put on estimates of reserves. As a matter of fact, this witness alone was in Denver for almost two months.

Trial Examiner: Mr. March, let's make this as short as we possibly can. I don't need any extended argument, I don't believe.

Mr. March: Very well, I have all the argument I care to make.

Trial Examiner: Have you anything to say, Mr. Keffer?

Mr. Keffer: Mr. Examiner, very briefly this Exhibit 315 merely presents an issue which was raised in the hearing at Denver. The Examiner will recall that Mr. Hughes, while on the witness stand on cross examination, testified as to a method or an estimate based upon pressures squared which matter had been brought out by Mr. March in his cross examination.

This is simply gathering up the loose ends on that. As it stands in the record now, it perhaps is due us or, at least, possibly the burden is upon us to make an explanation of just what he meant on that and that is all this purports to do. It is merely redirect of a matter that was brought out on cross examination.

Trial Examiner: I might say, Mr. Keffer, that the Examiner at this stage of the proceeding is very hesitant to take further testimony with respect to reserves of the Panhandle field.

I feel that every opportunity was afforded both the Respondent and the Commission's counsel to present evidence pertaining to reserves in the field at the time we were in Denver and the purpose of this hearing today was, of course, directed to taking of the testimony of Mr. Payne and Mr. Lerch.

Now, I don't intend to foreclose consideration of any other matter at this time but I do feel that we have adequate testimony in the record pertaining to the reserves or, at

least, that ample opportunity has been afforded to submit that testimony in the proceeding we had at Denver.

Therefore, the Examiner is inclined to sustain Commission's counsel's objection to the introduction of any further testimony on reserves at this time.

Mr. Keffer: I take it, Mr. Examiner, in order that we might complete our record in this respect, and to save time and eliminate the reading of what the testimony would be, let the reporter copy it in.

Mr. March: We object to this going in the record. Mr. Examiner, that is just putting it in the backdoor, copying it into the record. This is a new estimate of reserves. I have just glanced through it, but we don't object to having the thing marked for identification so you will have a record shown but that is just a way of putting the thing into the record, having it copied into the record.

Mr. Keffer: Mr. Examiner, I don't know any way of making a record, in fact, there isn't any way except to state what the testimony will be and I cannot do it except to read it. I thought we might save the time of the Examiner and counsel by putting it in this way.

Trial Examiner: Why not do this, Mr. Keffer. It is your desire to make an offer of proof, I take it?

Mr. Keffer: That is it exactly but I must show what the offer will be.

Trial Examiner: I was going to suggest that inasmuch as this is part of a document which has been marked for identification as Exhibit 315, perhaps it would be expedient to make an offer of the exhibit itself and the Examiner, in conformity with the statement he has made, will reject the offer and then the exhibit is a part of the record.

Mr. Spencer: If it may be understood, Mr. Examiner, that in making such an offer, the written statement will be considered, for the purpose of the offer, as being a part of the record.

Trial Examiner: I think it will be so understood.

Mr. March: That is satisfactory but did I understand the

Examiner to say it will be a part of the record, even though it is rejected?

Trial Examiner: If I said that, that is an erroneous statement. I meant even though this exhibit were rejected, it still went to the Commission as a part of the proceedings. That is what I intended to say.

Mr. March: It is a rejected part of the proceedings.

Trial Examiner: It is a rejected exhibit but it is transmitted to the Secretary as a part of the proceeding.

Mr. Keffer: All right. The Examiner will give us an exception, of course.

Trial Examiner: Surely.

Exhibit 315 is as follows:

Exhibit No. 315

Written Statement of

C. Don Hughes

During my cross-examination in these proceedings in connection with my testimony presented on pages 14455 to 14461, inclusive, of the record, I stated that I was watching the performance of the Texas Panhandle Field and studying the matter to see if another method (referred to as a pressure squared method) which I described in my testimony was actually working in the field and would solve the difficulties arising in the attempts to apply the so-called pressure decline method to the problem of estimating reserves of the field. I stated further that my observations indicated that the field was working as this pressure squared method indicated it should be and that therefore the remaining reserves in the field might vary directly as the square of the remaining pressure at the time rather than according to the commonly accepted method involving variation directly proportional to the pressure. I have been requested by counsel for Canadian River Gas Company to prepare this statement in further explanation of the study mentioned above and the conclusions reached therefrom.

Additional study and investigation since the date of my cross-examination has revealed to me that the method of

estimating gas reserves in the Panhandle Field, based on the squared pressure relationship, produces more consistent results than any other known method. The truth of this statement is strikingly demonstrated when pressure squares at different periods are plotted against cumulative production for such periods, and the straight line is drawn which most closely represents the observed data.

There is attached hereto Chart I on which the squares of the weighted average pressures of the field for the mid-year tests of 1935, 1936, 1937, 1938 and 1940 are plotted against the cumulative production of the field for each period from August 1, 1935. This is the period in the history of the field in which the most reliable data for both pressures and production figures have been obtainable. A straight line which most nearly fits the plotted points has been drawn upon the chart, and it may be noted by inspection of the chart that the distances by which the individual points differ from the line are so slight as to be negligible. The fact that a straight line so closely represents the points plotted in this manner indicates that there no doubt is some physical condition existing in the reservoir which is measured by the method of squaring pressures. Because such a straight line is not obtainable by any other method, that physical condition must be distorting the results obtained by applying the usual volumetric method, and results obtained from the latter method must be inaccurate and unuseable.

One explanation of the existing physical condition, which would indicate that the pressure squared method is properly measuring its effect in this case, has been advanced by Dr. Stanley C. Herold, a petroleum geologist and production engineer formerly associated with Stanford University, in his book entitled "Analytical Principles of the Production of Oil, Gas and Water from Wells" (Stanford University Press, 1928). Dr. Herold's publication relates that he had observed this same difficulty in using data available to measure reserves a number of years ago, and discovered that Jamin had done considerable research in France about 1860 on the flow of gas through capillary tubes which contained small globules of water; that Jamin had set out certain laws concerning the behavior of gas flow under these conditions. Dr. Herold applied these laws by mathematical analysis

to the problem of gas reservoirs, and his study indicates that if a reservoir fulfills the necessary qualifications for capillarity to affect the flow of gas from the reservoir, the relation between gas withdrawals and squared pressures must be a straight line. In our case we secure the straight line from plotting the results of withdrawals in the field and it is not unreasonable to assume that physical conditions in the Panhandle Field do fall within the classification which Dr Herold defines.

The projection of the straight line on Chart I to the production axis indicates that there was a remaining reserve of approximately 12.6 trillion cubic feet at 16.4# pressure base down to 0# well-head gauge pressure as of August 1, 1935.

The question as to what production prior to August 1, 1935, would have caused a reduction from virgin pressure of 430# to the pressure in 1935 is answered by the straight line, extended backward and up to the ordinate value of 184,900 (the square of 430) where it indicates prior withdrawals of approximately 5.1 trillion cubic feet. This amount differs by only 2% from the 5.2 trillion shown by Mr. C. J. Peterson's production tables, which were obtained by accumulating all available production data and estimating gas withdrawals where they were known to exist but for which no measurement data were obtainable. This would indicate that the withdrawal figures commonly accepted by the industry and the Railroad Commission of Texas for production of gas prior to standardization of measurement basis in 1935 are reasonably correct.

Chart I shows that the total original reserves in the Texas Panhandle Field were approximately 17.7 trillion cubic feet, which is the sum of production prior to August 1, 1935 (5.1 trillion) and the indicated reserves remaining at August 1, 1935 (12.6 trillion).

Table I below is a tabulation of the data from which Chart I was plotted.

Table I

Basic Data

Date	Weighted Average Well-Head Pressure R.R.C.*	Weighted Average Well-Head Pressure Squared	Cumulative Production from 8-1-35 MCF at 16.4 # Base
8-1-35	362.51	131,414	0
7-1-36	355.00	126,025	556,485,654
7-1-37	347.05	120,444	1,109,367,056
8-1-38	337.66	114,014	1,732,292,217
8-1-40	318.31	101,321	2,884,710,964

*The weighted average pressures are the computations of the Railroad Commission of Texas.

The record reflects the following with respect to additional testimony at Washington:

Mr. Lange: Mr. Examiner, there has heretofore been filed in this proceeding by the Colorado Interstate Gas Company an application for the taking of some depositions in this proceedings. Commission's counsel has been advised by general counsel that it is the Commission's desire that instead of having a deposition taken or depositions taken in the proceedings that it be suggested to the Examiner that at the time the proceedings here are concluded the Examiner will recess the proceeding to be resumed in Washington, D. C. for the purpose of taking those depositions or taking the testimony of those witnesses in Washington, D. C., rather than having to take the depositions. Commission's counsel, therefore, at this time would suggest to the Examiner that instead of taking depositions in the proceedings at Washington, D. C., that this proceedings be recessed to be subsequently resumed in Washington, D. C., for the purpose of taking the testimony of the witnesses named in the application.

In that respect, in order to expedite the final conclusion of this proceedings, we would suggest that the resumption of the hearing be had in Washington, D. C. at the earliest possible date and also that the proceedings there be confined to the taking of the testimony as applied for by the company.

The Trial Examiner: I think with respect to the practicalness of adjourning this hearing to Washington in order to take the testimony of Mr. Lerch and Mr. Payne it is much more practical to do that than to attempt to take their depositions. The Examiner will be inclined to follow that request of Commission's counsel; however, I am wondering, Mr. Brock, what the thoughts of respondents are with regard to the time that will be necessary to get ready to take this further testimony.

Mr. Brock: Mr. Examiner, of course we are breaking up here after five months—after a five-months' session—and apparently everybody will need a little time to get home and look around and perhaps take care of a few personal matters. Mr. Spencer and Mr. Dougherty and some of the rest of us have talked about it before and it was their suggestion that we reconvene April 28th. It was thought there would be no serious delay if that much time were taken.

There is one other thing I want to say, too, Mr. Examiner, in connection with Mr. Lange's last remark. I haven't understood in connection with this future hearing in Washington the thing was to be strictly limited to the testimony of the witnesses whose depositions we had applied to take. I haven't discussed that as fully with Mr. Dougherty and Mr. Spencer as I might have done, but my understanding was—I know Mr. Lusk has referred several times to some allocations or separations of an exhibit which he was interested in, and Mr. Rhodes has given attention to that particular study but didn't get it completed when he left here on account of illness and went to Florida. After coming back from Florida, my advice is that he has been very much engaged in some more natural gas cases before the Federal Power Commission, I believe, and the result is that I have had in mind all the time that would be possible; that it would be possible to introduce such an exhibit back there at the Washington hearing and possibly anything else anybody might have overlooked in this long five-months' hearing here in Denver.

I don't mean by that that either side should reopen this case and start trying it all over again, but there is a possibility of a mishap on either side on some particular item

Mr. March: If the Examiner please, the Commission's counsel's position is that we shouldn't wait until April 28th to reconvene in Washington. That would be four weeks' time and we should reconvene in two weeks, or a shorter length of time. If we wait to reconvene at Washington until that late date, this hearing will be going on June 1st and it seems we should not do that.

In the second place, we object to any testimony in Washington other than the testimony specified in the application of the parties which counsel signed. Our purpose has been to finish this hearing. If we go to Washington and leave this exhibit and that exhibit and this witness and that witness coming up, we will be trying this case all summer, and we most strenuously object. We object to any such a construction or arrangement to be made. There have been certain specific reservations made here.

Mr. Brock: I would like to make a reservation—

Mr. March: We object to that most strenuously. It is a thing we have been fighting to do, to get through with this hearing. This thing can run on and on and on and on as so many hearings have done with appreciable results.

Mr. Brock: I submit, Mr. Examiner, on each side here after this long drawn-out hearing, not having had an opportunity to review what evidence has gone in in detail, that it would be beneficial to keep the case open should either side discover something which ought to really go in. It wouldn't be surprising if something has been overlooked on either side and I don't think there is any such grand rush as Mr. March has been talking about.

The Trial Examiner: Let me say this: First of all, as to the date we might reconvene this hearing, the Examiner is going to be tied up in another hearing commencing in Washington on April 2nd. I have no thought at present as to how long that hearing might last, so I am reluctant to trim this time too closely.

In addition to that, the Examiner must insist that the record in this proceeding be corrected up to date and the stipulations submitted to the Examiner with regard to corrections of the record the day we reconvene in Washington.

Counsel are considerably behind in making corections of the record and that may require some time.

I had in mind, frankly, Mr. Brock, meeting somewhere around the middle of April.

Mr. Brock: We might consider the 21st which is the Monday preceding the date I suggested as the earliest date.

The Trial Examiner: Let me do this: I will set the time as April 21st, 1941, and then in the event the Examiner should not be free at that time or some other emergency arises, then we can make different arrangements at that time.

Mr. Brock: It is satisfactory to try it that way.

The Trial Examiner: The Examiner will set April 21st, 1941 as the date.

Now, with respect to the purpose of proceeding back there, the Examiner feels that the proceeding should be directed to the purpose of taking the testimony of Mr. Lerch and Mr. Payne; however, the Examiner is fully cognizant of things that are sometimes overlooked in continuing a hearing as many days as we have in this case.

While at this time the Examiner feels that proceeding back there should be for the specific purpose of taking the testimony of Mr. Lerch and Mr. Payne, nevertheless, the Examiner is perfectly willing to consider at that time the merits of additional testimony of either counsel for the respondents or Commission's counsel might have and to consider the offering of that testimony at that time rather than to attempt to leave the hearing wide open, so to speak, without some definite purpose on the adjournment to Washington.

Hughes also testified (Vol. 95, pp. 14528; 14569-14570; 14582-14594; 14623-14626) as follows:

Q. Is this the first time you have ever made any study of the Canadian River wells?

A. Of the Canadian River wells?

Q. That's right.

A. Well, I think that the information that I have shown

you shows, even if I had only read this information, it would show that I have made a study of the Canadian River wells.

* * * * *

Q. Did you ever think about checking your alleged drainage by the actual conditions that existed in Canadian River acreage prior to 1932 and in the west part of the field prior to 1932?

A. No, I made no study prior to 1932 of the type that I have shown here.

Q. Then how do you know that gas was not draining to the Canadian River acreage at that time in 1932?

A. It might have been. My interpretation is that it has not, due to the values that I have assigned. Now, if at 1932 some of this total production that the Canadian River had produced at that date of 94.4 billion, if none of that—I mean if they had lost no gas in addition to that by drainage, then my study would become a definite indication that my factor .919 is too large.

Q. Too large?

A. And then I would apply a lower factor to all those Canadian River leases and it would end up with a less estimate of reserves on the basis that they had obtained from their own leases, every foot of gas at that date, and if you assume that they had obtained more than some of their own gas, it would still further reduce this factor basis, which then in the end would wind up that I would come out with an estimate of reserves that is smaller than the one that I do come out with in this study. That is the only conclusion that could follow. Now, whether that is actually the case or not, I don't know for sure, but it is my interpretation that the conditions as I have shown in this statement on Canadian River reserves is the basis—is the best possible conclusion that I arrive at.

* * * * *

Q. Mr. Hughes, have you made a study by years of the pressure declines of Canadian River's acreage and the production of Canadian River's production as a whole by years all the way through to ascertain as to whether there has been any drainage from the area?

A. No, not the way you have described it. I have made a study, that is, I made a study in the middle of 1932, the

middle of 1938 and the middle of 1939, and the results are shown here.

Q. Mr. Hughes, you have here a figure for August 1, 1938 as of that date—it is a drainage figure, which you say has been drained away from Canadian River acreage, it being the difference between your production and depletion figure. Why did you skip those intervening years?

A. I don't know. It was really of no importance. One reason I went back to 1932 is that it was my opinion, generally speaking, the production from Canadian River acreage at that date accounted for the pressure loss, so the study for that date was for the purpose of trying to test the reasonableness of my factor.

If I had come out with a much greater apparent loss by drainage, I would have been inclined to think my factor was wrong. If I had come out with an apparent drainage into the Canadian River acreage at that date, I would have again concluded my factor was wrong. But since it came out so close, I considered it a good check on my factor. The reason I used 1938 and 1939 was that I wanted to make a test of what was going on currently. Those were the last two years I had at my disposal, and knowing that the production was shifting over into that general area from other parts of the field, I wanted to test the current performance. A year was a handy period to *chose* because the tests were made from one year to the next.

From 1938 to 1939 was the most recent year and naturally I wanted to make the test in the light and effect of the shifting of production into that area. That is the reason.

Q. I see here in 1938 and 1939 you tried to measure in percentage the drainage which has taken place from Canadian River's acreage.

A. I tried to measure—I obtained a percentage figure which represents the difference between depletion; that is, the amount of depletion which Canadian River produced.

Q. I gather you disagree wth Mr. Gill in that you think you can measure drainage quantitatively from the Canadian River?

A. That is what I attempted to do.

Q. Did you hear Mr. Gill's testimony that he couldn't do it quantitatively?

A. I don't know that he said that. I heard his testimony.
Q. On Page 11 of his written statement—

Mr. Spencer: Which exhibit is it, Mr. March?

Mr. March: Exhibit No. 266.

He states: "Since the original per acre reserves varied widely as between different parts of the area, such a quantative calculation cannot be made from the figures given on the table."

The Witness: What table is he talking about?

By Mr. March:

Q. The previous paragraph: "The figures arrived at in both of the above studies reflect the effects both of drainage and of original difference in reservoir content. If it could be assumed that the original reservoir content expressed in terms of total gas per acre was the same in all parts of the field, these figures could be used to obtain a quantitative expression of the drainage that had occurred into and out of the zones of pressure loss up to the time when the study was made."
A. Is he talking about Canadian River acreage?
Q. Yes. Didn't you hear his testimony?
A. Yes. He is apparently talking about Mr. Hammer's quadrants. I don't think what you were reading had anything to do with the question you asked me.
Q. Is that so. So you don't think Mr. Gill stated that he couldn't measure drainage quantitatively? Is that your position?
A. With respect to Canadian River acreage?
Q. That is right.
A. You haven't shown me where he did.
Q. All right, sir. I just wanted to get your position.

You state here that approximately 27 per cent was drained away between 1932 and 1938, is that correct?

A. No, that—
Q. That is the last year.
A. The percentage figure you are reading there—I think you will find that refers to the percentage of the depletion of Canadian River leases from the beginning of the field to the date 1938.

Q. How much gas has been drained away from Canadian River acreage between 1932 and 1938 according to your contention?

A. I don't know. I don't know that it is figured here.

Q. Have you made such a calculation?

A. No, but we can do it. It would be the difference between—from these figures on Page 3 you could determine that.

Q. What is the amount of difference between the depletion and production? What would be the amount drained away from 1932 to 1938?

A. Now, what was it you wanted—the percentage?

Q. I want to know the amount of gas in Mcf. which has been drained away according to your figures from Canadian River acreage from 1932 to 1938.

A. I have gone through the arithmetic and unless I have made a mistake, it is 29,821,939 cubic feet.

Q. Which has been draining away?

A. Between July 1, 1932 and August 1, 1938.

Q. And as we found out a few minutes ago, your figures showed that approximately 21 million Mcf. had been drained away prior to 1932?

A. Yes, that's right.

Q. All right, Mr. Hughes, how do you account for the fact that if 21 million had been drained away prior to 1932 that only 29 million according to your figures were drained away from 1932 to 1938, during the most prolific production of the field?

Mr. Spencer: Are you saying millions or billions, Mr. March? I believe you said millions.

Mr. March: Yes?

Q. Is this 29 figure in millions of Mcf.?

A. It is in millions of Mcf. It is billions of cubic feet —29.8 billions of cubic feet.

Q. Is that the same unit we used when we measured the 21 million prior to 1935?

A. Of Mcf., that's right.

Q. How do you account for the fact that whereas with very few wells adjoining Canadian River, if any, prior to 1932, 21 million was drained away and with a great deal of production around Canadian River acreage since 1932 only

29 million according to your figure has been drained away?

A. I don't know how to account for it. That's just the situation. That's just the way it works out.

Q. Now, Mr. Hughes, you come here to the map and show me where that 29 million went to that drained away from 1932 to 1938.

Mr. Spencer: He doesn't have to come to the map to show you that.

Mr. March: Well, anywhere. I don't care.

The Witness: Well, it will be going to areas of lower pressure than the pressures from which it was drained, wherever those lower pressures exist, that's where it would be going.

By Mr. March:

Q. All right, now, what part of the Canadian River acreage was drained during that period? It couldn't have been drained, could it?

A. All of the Canadian River acreage being drained?

Q. Could all of the acreage have been drained during that period?

A. Do you mean that that drainage was uniform from acreage scattered over the—

Q. No, I mean, could all of the acreage have been drained during that period—some gas out of it?

A. Well, it would depend upon the pressure pattern in the acreage. This is an overall figure. This is the net result of their drainage. Now, the drainage had to be going in that direction of lower pressured areas than the pressures in the Canadian River acreage. I think that is obvious. Now, just where those particular areas were generally speaking, they are in a northeast direction from the Canadian River group.

Q. Now, come up here on the map and show me approximately where that Canadian River gas was going specifically.

Mr. Spencer: Do you want to refer to Mr. Dunlap's map?

The Witness: Well, those I think would be sufficiently—they are sufficient to indicate where the low pressure areas are. Due to the fact that the yellow is the highest pressure

color on this set of maps, Exhibit No. 239, then the orange is the next lowest group and the next lowest group is the blue and the green—by the time you get out the green you are getting out pretty close to the edge of the Canadian River area as a group of leases that I am talking about. What I am talking about Canadian River group of leases, I am referring to this group of colored leases here on Exhibit 95.

Now, by 1938 the green area is the area that is approximately less in pressure than all of the rest of the Canadian River area. Therefore, the Canadian River group of leases as a group, the drainage would be from then out in that direction. It would be in the direction from the Canadian River group of leases of southwest Hutchinson County.

Q. Drainage through southwestern Hutchinson County?

A. No, it would be draining into the area of southwest Hutchinson County.

Q. The green area?

A. Shown in that green color, the travel of gas being from the blue area into the green area and from that orange-colored area into the blue and from the yellow area into the orange. Now, that is the general—the only conclusion that you can make from the pressure setup.

Q. Now, Mr. Hughes, I have already asked you about 1933, about whether or not you could tell me whether or not those pressures were caused—the declines were caused by drainage there in the southwestern part of Hutchinson County or by production. I will now refer you to the 1934 map.

Mr. Hughes, you see that portion where it shows 400 to 350 pound pressures there extends over for the first time over into the corner of Potter County from Hutchinson and over into some of the Canadian River acreage in Moore County.

Now, I will ask you this question; whether or not the declines in pressure there during that year period was caused by production from Canadian River wells within the area or whether or not that was caused by drainage.

A. In my opinion it was caused by both.

Q. Have you made a study of the production of the individual wells in that zone?

A. No, not of the individual wells.

Q. Have you made a study of the production from the Canadian River wells as a whole in that zone during that period?

A. No, I haven't, and I don't think it would be possible to arrive at a conclusion—a conclusive opinion from such a study, since the pressure contours indicate that drainage is going on. Then, the production from wells in that area of course influence the reduction in pressure but the actual total reduction in pressure in the area is a result of both the production from wells in the area and the drainage from the area.

Q. How can you state that it is when you haven't made a study of the production decline in the entire year period of time?

A. Well, I thought I made it clear.

Mr. Spencer; He has answered that question, Mr. March.

Mr. March: You mean by stating that his exhibit shows it?

Mr. Spencer: He said such a study wouldn't show you anything.

Mr. March: Well, he never made a study. He doesn't know whether it would show anything or not.

Q. Now Mr. Hughes, you see the 1935 map. You see there is, in Mr. Dunlap's map there, there is a slight intrusion—a little further intrusion of the brown 400 to 350 pound zone over to Potter county?

A. Yes.

Q. And there is a still further movement of the zone over into Moore County, Canadian River acreage?

A. Yes.

Q. Now I will ask you the same question—if I would ask you the same questions relative to the movement of those presures back as I did to the previous 1934 map, would your answers be the same?

A. Yes, that that pressure condition is due to both production from wells in the area and drainage of gas from the area, yes that's right.

Q. And that you have not made any study relative to the

production of the individual wells in the area during the period of the pressure decline of that period, or the total production from those wells?

A. For that period?

Q. That's right.

A. No.

Q. Now, next we come to 1936 and we find that the brown area which is 400 pounds, has intruded a little farther into Potter County, down into Potter County.

A. Yes.

Q. Now, if I should ask you the same questions in regard to that that I asked you in regard to the previous ones, would your answers be the same?

A. To the area as a whole?

Q. Yes, sir.

A. That the effect of those pressures is due to both production from wells in the area and drainage from the area?

Q. Yes.

A. Underground drainage from the area?

Q. Yes.

A. Yes.

Q. And have you made a study of the individual wells in that area during the periods of pressure declines by years, or the production from the wells as a whole in that area during that period?

A. No, I haven't made that study.

Q. Now, Mr. Hughes, we come to 1937 and I note here that there is some change in the configuration of the 400-pound pressure in Potter County and that there is a further intrusion into Moore County of the lower pressure area, but I note with a great deal of interest here that in the western part of Potter County that the pressures have increased back clear over the Potter County line into Moore County and that low pressure area has been wiped out in Potter County.

Now, that indicates that during that period, doesn't it, that the pressure has increased in Potter County in that area?

A. That is my interpretation, and that is why I mentioned a while ago in connection with the 1936 map that if you meant from the area as a whole. I recognized that

little extension that is sticking back in there into north Potter County on the 1936 map. It is obvious from the 1937 map that that little area that stuck back into there was repressured. At least it is so indicated by the contouring on the 1937 map.

Q. Now, do you think that is a correct delineation of what has happened from your studies?

A. Yes, definitely. Again, the effect of that pressure is due to the combination of production and drainage. In that particular case it would be my conclusion that the production during that particular time wasn't quite as great as the drainage was into the area, and, therefore, the pressures built up, assuming those are correct pressures. We are assuming that those were the correct pressures and the maps were made correctly, and I have no reason to doubt either one. I am just telling you what was involved.

Q. Have you made a study of the production in that area by years in 1937 of the pressure increases of the individual wells or decreases?

A. No, I have not.

Q. Now, Mr. Hughes, you would have to show a gain in pressure and reserves of Canadian River Gas Company in 1937, wouldn't you, if you had it done on a yearly basis?

A. Yes.

Q. You would?

A. Yes, the pressures came up. I think you will find there are some examples of that in the study that you have marked Exhibit 280. If the pressures have come up, naturally, over the previous period, when you treat that particular tract, that very treatment of it shows that that tract had gained a little.

Mr. Spencer: You are talking about tracts or the whole Canadian River area?

The Witness: Tracts, I was thinking of there.

* * * * *

Q. Oh, yes, I challenge you to show me one well up here to which gas has moved away from the Canadian River Gas Company in 1939.

Mr. Spencer: Now, Mr. Examiner,—

Mr. March: As distinguished from this—these other years.

Mr. Spencer: Here I am on my feet again. I don't see why it is necessary for counsel to challenge anybody here. If he wants him to point out a well, if he knows, then that's all right.

Mr. March: I'm sorry I said "challenge."

The Trial Examiner: This is up to 1939?

Mr. March: That's right.

The Witness: The year ending 1939?

By Mr. March:

Q. Ending July 1, 1939.

A. Mr. March, in order to pick out a particular well that could have obtained, and in my opinion would have obtained some of the gas that was lost by leases owned by the Canadian River acreage during the year ending 1939, I could construct for you on Mr. Thompson's contour map a little geometric pattern going down his pressure contours at right angles to those contours in such a way that the arrangement of the area between one limit of this area and the other limit would be the expanse of the Canadian River acreage and I would merely follow on down his map by going at right angles to his contours to where that method going from one contour to the next would finally bring me in to the lowest pressure in the pattern.

Now, then, to be specific, I would go to the Railroad Commission and get a list of each well in that area whose pressures were lower than the Canadian River leases and each well in that area that had produced a cubic foot of gas in that year ending in 1939. I would list in that list not only one well for you but I would give you the whole list that in my opinion would include the wells that in my opinion were getting some of the gas that started from the Canadian River leases during that year.

Now, just how far out, as you go down-dip in a pressure manner, the particular gas that left Canadian River leases during that period had extended by the end of the year, I wouldn't attempt to say, but sooner or later those would be the wells that would eventually get some of the gas, or at least some of the gas that was being replaced by gas that had started from back up there in the Canadian River leases.

Q. Mr. Hughes, you have never made such a study, have you?

A. I never have made such a study?

Q. Yes.

A. No, I haven't.

Q. Now, Mr. Hughes, you criticised Mr. Hammer because his production declines—I mean, his production pressure figures you said would not approach a straight line, but have a downward trend. Now, would your figures approach a straight line for the pressure decline method that you have utilized?

A. How do you mean that I have utilized—on the tract-by-tract—

Q. No—yes—in other words, you have an estimate in which you use a pressure decline method at 7-1-32, 8-1-38, and 8-1-39.

A. Well, the way I have applied Boyle's Law in each tract, I am assuming that it is a straight line. Now, you were confusing—I have not applied the pressure decline method in this study. I started out with my estimate of original content in each tract and I applied Boyle's Law and found the computed amount of gas that was lost by all the tracts and made a comparison to that figure of production that had been taken from those tracts. The thing that you have tried to ask me to compare, I don't think is comparable. I haven't said that Boyle's Law wasn't working in the field. I said the pressure decline method applied to the field is not working. I have assumed that Boyle's Law is working, but as I have explained before, I am not so sure now that we know correctly just which manner we should apply Boyle's law.

Testimony of Stanley Gill, Witness for Canadian

Necessity for a Correct Equilibrium Pressure

Stanley Gill, whose qualifications have heretofore been given, testified with respect to the several estimates of reserves introduced in this case and particularly with reference to the pressure-decline method as applied to the Texas Panhandle Field and the absolute necessity of having a correct equilibrium pressure before this method can be ap-

plied. His testimony on direct examination is contained in his written statement in Volume XCI, pp. 13981-13998, and in Exhibit 265, pages 5 to 18. The following is a statement of Gill's testimony.

The several estimates of reserves made in this case were subjected to careful scrutiny and study. Attention has been given to the correctness of methods employed, to the manner in which they have been applied and to the applicability of the results in determining the future producing life of gas reserves in the Texas Panhandle Field. Witness analyzed these methods from the point of view of engineering fundamentals and also on the basis of his own knowledge of the Texas Panhandle Field.

While it must be understood that estimation of reserves of gas or oil is far from being an exact science, it must also be emphasized that reasonably accurate estimates can be arrived at by the application of proper methods. Such estimates are frequently used as the basis for very large transactions and expenditures. In such cases large sums of money may depend upon the validity of these estimates and accuracy is of the utmost importance.

The accuracy of an estimate of reserves of oil or gas depends upon the completeness and dependability of the basic data, upon the correctness of the methods of estimation and their application and upon the reliability and experience of the geologist or engineer by whom the estimate is made. Probably the most important of these is the experience of the individual who makes the estimates. Purely mechanical application of a procedure of estimation may be made by a raw and inexperienced graduate of a good technical school. Such an estimate, even though it be couched in highly technical terms and accompanied by maps and mathematical formulae, is usually quite valueless and would never be acceptable as a basis for purchase or sale of properties, for valuation as collateral for a loan or for determination of the advisability of large expenditures in operating facilities. Proper estimation of reserves requires not merely a knowledge of the mechanics of an estimating procedure, but also a critical faculty that can be gained only through many years of detailed experience. While witness is not prepared to go as far as a certain eminent geologist who once stated

that "geological instinct" was the only reliable guide to estimation of reserves, he is very definitely convinced that detailed familiarity with a producing area and a thorough background of experience in estimation of reserves are of vital importance if dependable results are to be obtained. The results are "estimates" rather than "determinations" of the reserves of oil or gas. The results arrived at cannot be exact, but they are dependable and can be weighed and compared by careful and critical scrutiny of the procedures by which the results were obtained.

Hammer, Commission witness, has made his estimate of reserves of gas in the Texas Panhandle Field by a pressure-decline method which involves several unique features. Witness is of the opinion that Hammer's estimates are neither correct nor applicable for evaluating the probable future life of the Canadian or field reserves. This opinion is based upon three lines of reasoning:

(a) A pressure-decline method in which withdrawals of gas are compared to declines of pressure, the latter being weighted only on surface acreages, is entirely incorrect for estimation of reserves of gas in the Texas Panhandle Field;

(b) Even if a method of this type could be correctly applied in the Texas Panhandle Field, Hammer's procedure would lead to entirely incorrect results. The weighted procedure used by him results in incorrect conclusions as to pressure-decline relationships for the field as a whole and is erroneous in its application to Canadian's acreage; and

(c) Hammer's estimate of remaining gas reserves under Canadian's acreage would be without value in the prediction of future producing life of this acreage, even if it were correct, since it fails completely to take into account the effects of future drainage.

There can be no doubt of the fact that pressure-decline methods, where they are properly applicable, afford an accurate means of evaluating reserves of natural gas. Where the data on a field are adequate for such an estimate, and where these data show that the pressure-decline method can be properly applied, the estimates of reserves and ultimate

recoveries are more accurate than can be attained by other procedures of estimation. For this reason, pressure-decline methods should be preferred to others for estimation of gas reserves in those fields to which such methods can be properly applied. In many fields, however, physical conditions are such that pressure-decline estimates may lead to widely erroneous conclusions. Indiscriminate and unreasoning application of pressure-decline methods, without careful study of their adaptability for the estimate being made, may lead to false results and conclusions.

Figure 1, attached to Exhibit 265, shows typical relationships between pressure-decline and accumulated total production and production per acre-pound in various types of gas reservoirs. Obviously, reserves can be calculated from pressure-decline only in those cases where pressure declines directly with production, or where the departure from direct variation is accounted for by deviation from Boyle's Law.

Gill further testified on direct examination that a straight line relationship cannot be applied for proper and correct estimation of reserves where the facts on a field, when plotted in curves such as those of Figure 1, Exhibit 265, do not conform to Boyle's Law.

The Texas Panhandle Field is definitely a field to which simple pressure-decline methods, involving weightings on surface acreage alone, cannot be properly applied. The theoretical reasons for this are elementary. Fundamentally, application of the gas laws and particularly of Boyle's Law, which expresses the relationship of gas volumes to pressures, are related entirely to volumes and not at all to areas alone.

Boyle's Law expresses a simple relationship. It states the fact that the quantity of gas contained within a rigid container varies directly with the absolute pressure. Doubling the pressure doubles the quantity of gas. By increasing the pressure ten times, ten times the quantity of gas can be stored within the container. Quantity, as thus applied, of course, means the actual weight of gas or the equivalent volume of gas at some definite base temperature and pressure. This law applies strictly to any perfect gas, regardless of the size or shape of the rigid container in which it is confined. Correct calculations can be made from it, however,

only when the actual pressure averaged throughout the entire volume of the container is accurately known.

The true weighted average pressure of gas in the Texas Panhandle Reservoir cannot possibly be determined, however, by weighting pressures against surface acreage alone. The reason for this is shown by Figure 2 attached to Exhibit 265, which is a reproduction of a drawing witness prepared in 1935. The top sketch on this page is a cross-section of the gas producing formation across the Texas Panhandle Field. The basic cross-section was prepared by C. J. Peterson from logs of actual wells. In the second drawing the distribution of original gas reserves across this cross-section is shown. The very great variation of gas content for equal surface acreages is apparent. In the third sketch an equivalent distribution of this gas in containers is shown. Each of these containers represents, in size, the volume of gas which originally underlaid an exactly equal surface area.

The true average pressure throughout the entire volume of gas in any gas reservoir can be correctly determined by weighting on surface acreage alone only under either of two sets of physical conditions. These are:

(a) When the pressure is equal in all parts of the reservoir; or

(b) When each and every acre in the reservoir is underlaid by exactly the same volume of gas-bearing voids.

When one of these two conditions exists the actual pressure existing through the volume of gas within the reservoir can be determined from a consideration of surface pressures and surface acreages, but this cannot be done under any other conceivable set of physical conditions. Since neither of these conditions exists, nor is even barely approached, in the Texas Panhandle Field, determination of average pressures by weighting on surface acreage alone cannot possibly lead to an evaluation of the actual average pressure existing through the volume of remaining gas, and therefore cannot possibly lead to a correct estimation of the gas reserves of the reservoir or any part of the reservoir.

The fact that the pressure-decline method, using pressures weighted on surface acreage alone, cannot be applied to the

Texas Panhandle Field, is conclusively demonstrated not only by unquestionable theoretical considerations, but also by all of the available factual data on relationships between pressure-decline and production of gas in the field. If surface pressure weighted on acreage alone could be correctly applied to estimation of reserves of gas in the Texas Panhandle Field, the yield of gas for any given increment of average pressure would always be equal. This is absolutely fundamental. Neglecting corrections for deviation from the gas laws (which are well known and which can be applied to any given case) the amount of gas remaining in any gas reservoir of constant volume, will be strictly and exactly proportional to the average absolute pressure existing through the volume of gas in the reservoir. If the volume of the gas-filled space changes, as for example in a field in which there is rapid water encroachment, this proportionality will not exist and pressure-decline estimates can be applied only by correcting for the changes in reservoir volume. This is not necessary in the case of the Texas Panhandle Field, where water encroachment is of such a minor character that its effect on reservoir volume can be entirely ignored. For such a reservoir the remaining quantity of gas, expressed in weight or in volume at a given base pressure, will necessarily and inevitably be exactly proportional to the actual average absolute reservoir pressure.

In the Texas Panhandle Field the original reservoir pressure was approximately 471 pounds absolute. When the actual average pressure throughout the volume of gas in the reservoir has declined by 25% to 353.3 pounds absolute, exactly one-fourth of the volume of gas which originally existed within the reservoir will have been removed. When it has declined 50%, to 235.5 pounds absolute, exactly one-half of the original gas will have been withdrawn from the reservoir. In other words, each decline of one pound per square inch in the actual average absolute reservoir pressure will be brought about by withdrawal of exactly 1/471st of the quantity of gas that originally occupied the reservoir voids. If this strict and exact equality of pressure-decline for equal volumes of gas withdrawal does not exist, it means either that the volume of the reservoir does not remain constant or that an attempt is being made to apply improper

gas withdrawal figures or incorrectly calculated average pressures.

(Note: Both Hughes and Hammer have used wellhead pressures which are 430 pounds.)

The lack of proportionality between gas withdrawals and pressure declines results almost entirely from incorrect pressure-decline figures. Massa and Hughes have submitted calculations based on Hammer's pressure and production figures. Their calculations show that the yield of gas per acre-pound or per pound decline in pressure has decreased progressively from year to year during the period covered by Hammer's estimates. The results arrived at by Massa and Hughes are shown in Exhibit No. 257 and Exhibit No. 258, respectively. This progressive decrease from year to year shows conclusively that Hammer's application of a pressure-decline method is totally incorrect and leads to an entirely false estimate of gas reserves. Hammer is not alone in this error. The same fallacy exists and can be conclusively shown to exist in any other estimate of gas reserves of the Texas Panhandle Field, based on declines of average pressures arrived at by weighting on surface acreage alone.

Hammer has overriden and ignored the lack of uniform relationship between pressure-decline and gas withdrawals by adopting as his fundamental premise the assumption that the curve expressing relationship between average pressures and accumulated total gas withdrawal is a straight line. He has, therefore, by application of an averaging procedure based on the method of least squares, drawn his curves as straight lines, or has applied an average yield per acre-pound per square inch derived from such calculations. His error is in incorrectly assuming a straight line relationship between pressure and accumulated total production. This relationship does not in fact exist between pressures, averaged by weighting on acreage alone, and accumulated total withdrawals in the Panhandle Reservoir. An actual plotting of Hammer's own figures connecting the points as he has determined them, demonstrates the fact that yield of gas for equal increments of pressure-decline are progressively less from year to year on the basis of average pressures calculated as he has calculated them.

The fact that the pressure-production relationships employed by Hammer in making his estimates do not come close to conforming to Boyle's Law, is proven by a consideration of the data contained in Table III of his Exhibit No. 180. In Figure 3, attached to Exhibit 265, curves of pressure against production, accumulated from August 1, 1935, are plotted from Hammer's results by "quadrants," as given in Exhibit No. 180. It is obvious that none of these is a straight line relationship, and that the application of Boyle's Law is improper. The great error resulting from Hammer's application of Boyle's Law is even more apparent from Figure 4 attached to Exhibit 265. In this figure, the variation in rates of recovery, per acre-pound, are plotted by "quadrants." If Boyle's Law applied, these would be horizontal straight lines. The actual uniform tendency, as shown in Figure 4, is such that application of Boyle's Law results in a gross over-estimation of reserves.

Hammer assumed that his pressure averages correctly expressed performance in accordance with the gas laws, when compared to gas withdrawals. On the basis of this premise he assumed that the relationship between these two factors should be a straight line. He therefore constructed straight lines by the application of a mathematical method which could, in fact, lead to the construction of a straight line to represent the distribution of bird shot in a shot gun pattern, but which leads in the application which he has made of it, to a conclusion which does not bear any reasonable relationship to the actual facts as they exist in the Texas Panhandle Field.

An additional major fallacy is found in Hammer's weighting of his "quadrants." The division of the field into such areas is a legitimate and proper procedure for convenience in measurement and computation. The division could also be used to study the drainage and pressure performance if the subdivisions had been laid out for this purpose. Hammer's "quadrants" are not, however, laid out in relation to pressure patterns, relative reserves or areal distribution of withdrawals. Up to the point of his determination of withdrawals and weighted pressures by "quadrants," Hammer has made legitimate use of his subdivision of the field area. From this point on his calculations based on his

"quadrants" are entirely incorrect. Under the procedure which he has employed, and in which he has combined with each "quadrant" all of the surrounding "quadrants," his results are entirely incorrect as applied either to any particular individual "quadrant" or to any combination of "quadrants," up to and including the complete combination used in arriving at estimates for reserves of the field as a whole. The reasons for these inaccuracies may be simply stated as follows:

(a) The values arrived at for any particular "quadrant" do not and cannot properly express conditions which exist within that particular "quadrant" at the time of the estimates. This statement is obviously true, since the values arrived at are not values for the particular "quadrant" under consideration, but are values for a group of "quadrants," including not only the particular "quadrant" under consideration but also all of the surrounding "quadrants."

(b) For the field as a whole the averages arrived at do not and cannot represent true average values, because unequal weights are given to different parts of the field area. In arriving at the overall averages, Hammer has used some of the centrally located "quadrants" eight or nine times, while some of the edge "quadrants" have been used only four or five times. By his procedure a given area in one of his central "quadrants" may have as much as two times as much weight in the final averages as does an equal area in one of the edge "quadrants."

The unequal weighting would lead to incorrect results, even if all the acreage had been equal in original reserve value, but is even more incorrect for the Texas Panhandle Field because it multiplies the weight given to rich "quadrants" in the center of the structure. This is readily apparent from the cross-section which was shown in Figure 2, Exhibit 265. Averages arrived at by any such procedure as Hammer's are incorrect and give an incorrect and distorted picture when applied to Canadian's acreage. Much of the Canadian acreage is located in "quadrants," the performance of which is inferior to that of adjoining "quadrants" within which Canadian does not hold acreage. By the method of

averaging employed by Hammer, the apparent value of these inferior edge "quadrants" is inflated by the inclusion of performance figures on other areas.

Finally, it may be very definitely stated that an estimate of remaining reserves in place under Canadian acreage as of any date, even though such an estimate were correctly made, would be entirely without value as an indication of the future producing life of such reserves. Such an estimate, expressing only a total quantity of gas in place, fails entirely to consider the effects of drainage, which will actually be of controlling importance in determining the future economic life of these reserves as a source of supply of gas for a trunk pipe line system.

Gill testified on cross examination as follows:

That from the very beginning of his experience in the oil business he was concerned with the problem of estimating reserves. (Vol. XCII, pp. 14070-14072.) That in estimating gas reserves he ordinarily used the pressure-decline and volumetric methods and as to oil, he used the production-decline method. (Vol. XCII, pp. 14081, 14082.) That he had made a number of estimates of reserves on gas fields (Vol. XCII, p. 14100), being fifteen or twenty gas fields in all. (Vol. XCII, p. 14128.) The gas fields concerning which estimates were made were covered in the cross-examination from pages 14085 to 14129.

The witness stated that the use of the term "volumetric" as applied to gas estimates was the method which considered sand thickness and porosity. (Vol. XCII, p. 14101.)

The witness was asked to define "equilibrium pressure." He stated that this was the true weighted average pressure within the formation; that any gas container—gas reservoir—which is inter-connected permeably, would reach an equilibrium pressure if all withdrawals were stopped and if sufficient time were allowed, assuming that there is no water drive and if there were no change in the gas bearing volume. In other words if such a field were shut in long enough it would eventually equalize at a pressure which would be equally the same as the true weighted average pressure.

"Now, that true weighted average pressure which is

> identical with what you call the equilibrium pressure, is the only pressure that could be used in a proper application of the pressure-decline method. (Vol. XCII, p. 14113.)

It is the true weighted average pressure (equilibrium pressure) that must be obtained before the pressure-decline method can be accurately applied. (Vol. XCII, pp. 14117, 14118.)

The witness was then asked if volume was not considered when pressures were weighted on surface area. The witness replied that this was not true, although surface is one of the factors in determining volume. He illustrated this by saying that the volume of a carpet covering the floor of a room is not the same as the entire volume of a room, but that is the assumption that is made when pressures in a reservoir are weighted on surface acreage alone.

The witness stated that he had endeavored to make many estimates of gas reserves in the Texas Panhandle Field based upon a proper application of pressure-decline methods and by the utilization of various methods of weighting and various methods of calculation. Each time that he has made such an estimate he weighed that estimate as impartially as he could and has decided in each instance that the estimates were not correct. None of the estimate stood up under his own analysis where he would be willing to accept them. (Vol. XCII, pp. 14140, 14141.) In making such estimates he was not looking for an answer but was looking for a sound method based upon pressure-declines in the Texas Panhandle Field and such estimates as he has made would not stand the test of unbiased engineering criticism; that he had tried hard to make an estimate that he thought was correct because he believes that there is some way of applying correctly the pressure-decline method of estimating gas reserves in the Texas Panhandle Field, but he is certain that it is not an elementary approach. Every elementary approach gives an incorrect result. (Vol. XCII, pp. 14178, 14179.)

He then again referred to Figure 2 attached to Exhibit 265 which is a typical cross-section of the Texas Panhandle Reservoir and which shows the correct deviation in pay

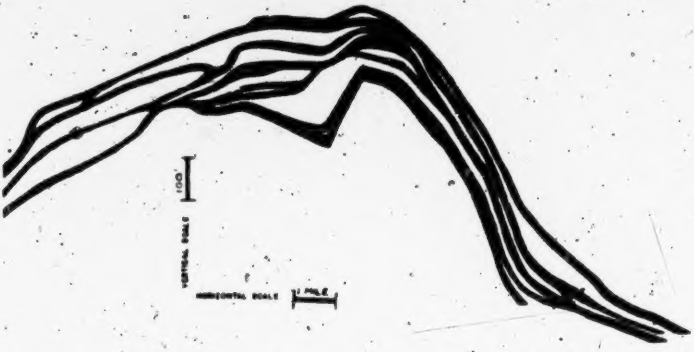
thickness from one side of the field to the other, and explained that this figure showed graphically why it was impossible to secure a true weighted average pressure (equilibrium pressure) by weighting pressures on surface acreage alone. (Vol. XCII, pp. 14156, 14160-14162, 14167.)

Hammer has not arrived at the correct weighted average pressure which most nearly approaches equilibrium pressure because he determines the average pressures weighted on surface acreage alone and the result does not closely approach equilibrium pressure. The witness then reiterated that the curves shown in Figure 4 attached to Exhibit 265 prove absolutely and without any doubt that the pressures utilized by Hammer are not the true weighted average pressures in the Texas Panhandle Reservoir. There is no question in the witness' mind about this. (Vol. XCIII, pp. 14270, 14271, 14273-14275.)

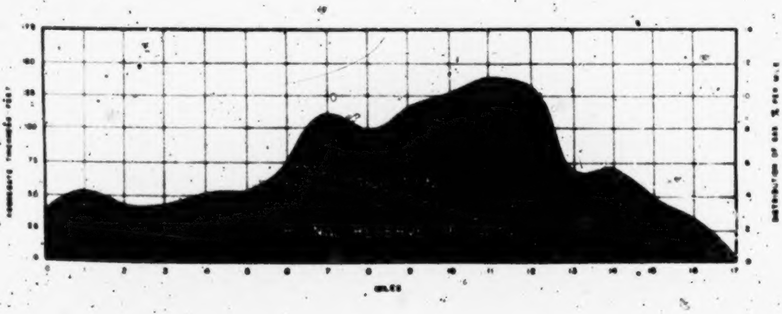
Exhibit No. 265

FIG. 2.
ILLUSTRATIVE CROSS-SECTIONS OF THE TEXAS PANHANDLE FIELD

CROSS-SECTION OF GAS-PRODUCING FORMATION.



TOTAL THICKNESS OF GAS-BEARING FORMATION.



EQUIVALENT DISTRIBUTION OF GAS IN CONTAINERS.

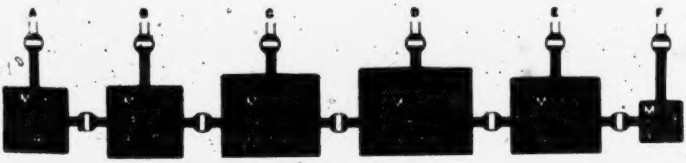
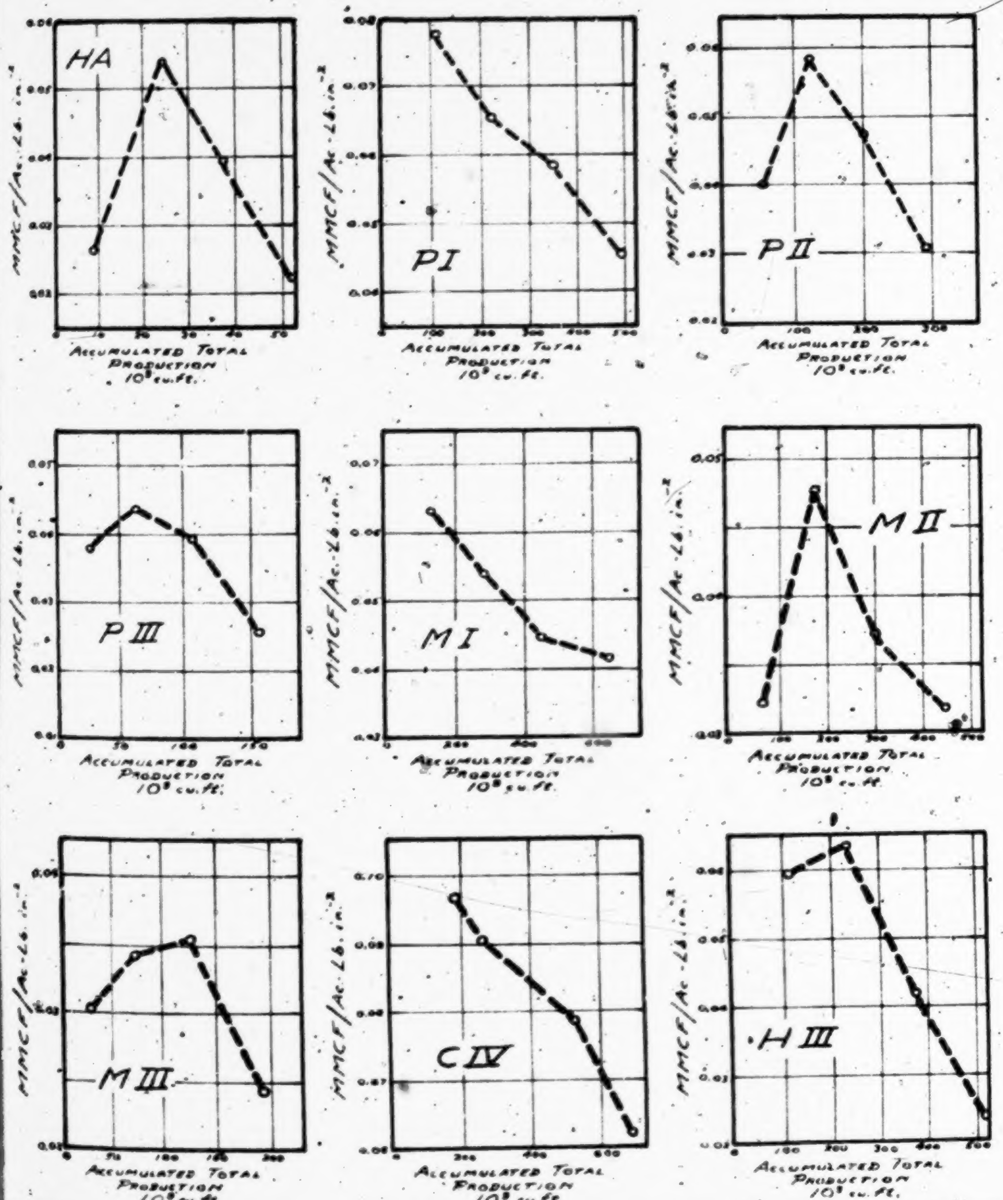


Exhibit No. 265

Fig. 4.
Variation in Rates of Recovery per Acre.-Lb./Sq. In. from Hammer's "Quadrants"

—— Computed from Table III, Exhibit #180



Analysis of Stevens' Method

Testimony of STANLEY GILL, Witness for Canadian

Stanley Gill, witness for Canadian, analyzed the methods and procedure utilized by Stevens, Commission witness, in estimating the recoverable reserves from Canadian's present wells. Stevens' estimate is contained in Commission Exhibit 182. Gill's testimony is contained in Exhibit 265, pp. 18-24, and in Volume XCI, pp. 13999-14006, and is summarized as follows:

The witness stated that Stevens' methods and procedure were entirely fallacious, because:

(a) Stevens estimated reserves by a decline method, by averaging the pressure performance of wells, and this did not truly represent actual average pressures within the reservoir.

(b) Stevens' curves for his individual quadrants were arbitrarily drawn. He did not follow a uniform procedure in averaging out the various points, and did not give the same relative consideration to the points for particular years.

(c) Stevens neglected or ignored his pressure points for 1935 and 1936 in the plotting of his curves, while such pressure points were utilized by Hammer in his estimate. The reasons advanced by Stevens for ignoring the 1935 and 1936 pressure points fall into the category of expediency, rather than sound engineering practice.

(d) Stevens did not construct his curves on the basis of the various pressure points but constructed a straight line that most appealed to his fancy in each particular case.

(e) Stevens arbitrarily assumed that Canadian would continue to produce the same proportion of gas out of each quadrant in the future that it produced in the past. (Exhibits 255, by Hendee, and 256, by Massa, show conclusively that Stevens' assumption is totally unjustified and incorrect.)

(f) Stevens assumed additions to reserves for each additional well completed, and, in doing so, ignored interference between wells and overlapping of drainage areas. This is fundamentally erroneous.

Gill stated further that Stevens' procedure in some cases led to ridiculous results, which is illustrated by his treatment of Potter Quadrant 3 and Potter Quadrant 1. Hammer's estimate of reserves in place in Potter Quadrant 3 was 448,272,000 Mcf. as of August 1, 1939. Stevens estimated that the nine wells in this quadrant, drilled on a spacing of about 3700 acres per well, would recover approximately 525,300,000 Mcf. from the same date, or about 117% more than Hammer's estimate. In contrast to this estimate, Stevens estimated that the twenty-four wells in Potter 1, which are spaced to an average density of about 2400 acres per well, would recover less than 45% of the volume of gas estimated by Hammer as remaining beneath this quadrant on August 1, 1939. Hammer's estimated reserve under this quadrant was 1,282,995,000 Mcf., while Stevens estimated that the existing wells of Canadian and others would recover only 568,800,000 Mcf. Stevens concluded that approximately fifty-two wells, on an average spacing of about 1100 acres per well, would be required to recover the estimated reserves from this quadrant. This would be more than three times the drilled density that Stevens estimated would be required to recover all of the gas, and more, underlying Potter 3.

Gill further stated that another basic error inherent in Stevens' calculations was the assumption that each well produces its gas from a separate and independent drainage area, which Stevens assumed bore a constant and unvarying relationship to withdrawals out of the well. Stevens then assumed that such additional wells will actually increase the ultimate total recovery, unless they are so closely spaced that interference will occur. The witness further stated that interference would actually take place between any two gas wells withdrawing gas from the same permeably inter-connected porous reservoir system. Gill stated that the assumption of Stevens might be correct as applied to oil but was wholly erroneous as applicable to gas.

Gill further stated that given a sufficiently long period of

time, a single well could drain all of the recoverable gas out of any permeably inter-connected porous system, even though the size of the system was as great as that of the Texas Panhandle Field. Additional wells after the first well would not add a cubic foot to the total quantity of gas that could theoretically be recovered out of such completely inter-connected system. Additional wells are drilled, not to add to the reserves, but to make possible recovery of the gas within a shorter period of time.

The drilling program of a gas well is determined by two factors:

(a) The necessity for a sufficient number of wells of sufficient producing ability to supply gas at a daily rate sufficiently high to satisfy the maximum requirements of the available market (peak-load demands). In Texas a well cannot produce more than 25% of its open flow potential, and actually a considerably greater open flow capacity should be developed. Operations to a full 25% of open flow are usually improper and will result in serious operating difficulties. The number of wells should be sufficient to supply the peak-market demands at some considerably lower percentage of total open flow capacity, and there should be additional wells drilled to provide an adequate supply when some wells go off production, which is a normal operating occurrence as wells become older.

(b) In many cases lease obligations, rather than the demands of the gas market, control drilling operations.

Abandonment Pressure in the Texas Panhandle Field

Testimony of Max K. Watson, Witness for Canadian

Max K. Watson, gas engineer and assistant general superintendent of Canadian, whose qualifications have heretofore been given, testified as to the rock pressure at which it will become unprofitable for Canadian to continue operating and maintaining its gas wells in the Texas Panhandle Field. His testimony on direct examination is shown in

Volume LXXXVI, pages 13037 to 13045 and Exhibit 254, pages 1 to 7.

(1) The rock pressure at which it will become unprofitable for Canadian to continue operating and maintaining its gas wells in the Texas Panhandle Field.

At 50 pounds rock pressure the back pressure method developed by the United States Bureau of Mines indicates that the average well of the Canadian will have an open flow capacity of approximately 1,000 Mcf. per day as shown by the curve attached to Exhibit 254. By applying the 25% of open flow capacity permitted by the Railroad Commission, the maximum allowable of such well will be 250 Mcf. per day.

A 65% load factor (approximate production load factor for 1940) applied to the maximum allowable will give an average well an average productive expectancy of 160 Mcf. per day, which when valued at 4c per Mcf. at the well amounts to approximately $6.50 per day, or approximately $2,375.00 per year before deductions for royalties and severance taxes amounting to approximately $595.00 per year at present average rates. Therefore, the net amount available for operating and maintaining an average gas well at 50 pounds rock pressure will be $1,780.00. Canadian's cost of operating and maintaining its gas wells in the past without including royalties, severance taxes or amortization charges has been in excess of this amount.

Past and present costs of Canadian for operating and maintaining its producing gas wells do not provide a dependable index for the purpose of measuring the cost of operating and maintaining such wells when they reach rock pressures as low as 50 pounds. Present wells of Canadian have been operating at comparatively high pressures and therefore have been free from many operating difficulties which will develop at lower pressures. As the rock pressure of a well decreases, its open flow decreases at a proportionately higher rate. As the open flow decreases, the well is less capable of keeping itself clean of cavings and free from water, which has a tendency to increase bridging in the hole, flooding and salting in the formation. Moreover, as the wells approach a 50-pound rock pressure, they will be older and the corrosion of casing by water at the forma-

tions in which the well is not producing will become a greater problem. Since a well of low open flow capacity is unable to free itself of its accumulated water, it may be necessary in many instances to pump or syphon off such water which will add substantially to the cost of operating and maintaining the wells.

It should be remembered that when a well reaches a rock pressure of 50 pounds the actual working pressure of such well is only about 40 pounds. It also should be remembered that past tests of the future capacity of a gas well to produce in the Texas Panhandle Field shows that such capacity is declining at a greater rate than is indicated on any specific date by use of the back pressure method referred to above. The fact is that all producing problems have the effect of decreasing a well's ability to deliver gas and causing a corresponding reduction in its producing characteristics as represented by the back pressure curve at any date. Therefore, the estimate given above of the open flow capacity of a well at 50 pounds pressure in the Texas Panhandle Field is a maximum estimate based on present data.

For the reasons above stated, it is his opinion that it will become unprofitable for Canadian to continue operating and maintaining its gas wells in the Texas Panhandle Field when the rock pressures of such wells have declined to 50 pounds.

(2) The rock pressure at which it will become unprofitable for Canadian to drill additional wells in the Texas Panhandle Field.

A study of the producing ability of an average gas well indicates that a total of less than 1,000,000 Mcf. will be produced from an average well between 125 pounds and 50 pounds rock pressure. Assuming a value of 4c per Mcf. at the well for such gas, the total value of gas to be produced between the rock pressures above mentioned will be less than $40,000.00. Deducting the current rate of royalty and severance taxes applicable to such gas would reduce the total amount above to approximately $30,000.00 which would be available for the payment of operating charges and amortizing the cost of the well with its fittings, meter and gathering line. He has heretofore testified that based upon present conditions, the cost of drilling and completing future gas wells with meter, meter house and gathering line, will

be $30,000.00 each. Obviously, the revenue to be anticipated from a well between a rock pressure of 125 pounds and abandonment pressure of 50 pounds is insufficient to pay the cost of operating, maintaining and amortizing the same, without taking into consideration any return on the investment.

Therefore, for the reasons above stated, it is his opinion that 125 pounds rock pressure represents the lowest pressure at which Canadian will be able profitably and economically to drill additional wells in the Texas Panhandle Field, and it may well develop that it will be economical and good business practice to discontinue drilling at a higher pressure.

(3) The number of wells which will be required by Canadian at certain pressures to furnish its estimated markets.

By the use of the back pressure curves referred to above it is estimated that Canadian will require a total of 212 producing gas wells at 125 pounds rock pressure in order to supply the peak obligations reached in the year 1940 of 186,000 Mcf. per day. Hendee's estimates for future years in his Exhibit No. 80 indicate an increasing average day in the peak month up to 216,000 Mcf. per day in 1946. This estimate of required wells is a minimum because of the decreasing ability of wells to produce gas as indicated by the change in back pressure tests heretofore taken on the same wells at different dates. Also, it has been assumed that each new well drilled in the future will be an average well, which may not be realized since a substantial portion of the undrilled acreage of Canadian is indicated by its geologists to be in so-called areas of less than average or low potential.

By the same method of calculation it is estimated that Canadian would be required to drill 78 additional wells in order to meet the same market requirements of 186 million per day betwen a rock pressure of 125 pounds and 100 pounds; likewise, a total of 725 wells would be required to furnish such markets down to a 50-pound rock pressure, and a total of 1,675 wells down to a 25-pound rock pressure.

A total of 212 producing gas wells will permit an ultimate spacing of wells by Canadian of approximately 1,200 acres per well. Generally, such a spacing should so distribute the

Company's wells among its various leases as to automatically provide for proper internal proration. In some instances, however, internal proration as between leases will not permit certain wells to produce at full capacity as allowed by the Railroad Commission, which again serves to make the above estimates of total wells required a minimum rather than a maximum estimate.

It should be emphasized that the 212 wells estimated above will only be able to supply the market requirements referred to so long as the rock pressure of such wells remains at 125 pounds. As the rock pressure declines with subsequent withdrawals, the producing capacity of the 212 wells will decrease in a greater proportion than the rock pressure until the abandonment pressure of 50 pounds rock pressure is reached.

There is attached to Exhibit 254 a back pressure curve which represents the average well of Canadian. It will be noted that there is indicated upon the curve the expected open flow of the average well at 125 pounds pressure, 100 pounds pressure, 50 pounds pressure and 25 pounds pressure. The open flow as indicated represents the maximum producing ability of the wells at the various pressures indicated. The wells, of course, can produce legally only 25% of this amount due to statutory restrictions.

The witness testified on cross-examination that although he had not prepared a formal study with respect to abandonment pressures similar to the study contained in Exhibit 254, that he has at all times kept the matter in mind and is continuously studying the general question of abandonment pressures. (Vol. LXXXVIII, pp. 13214, 13216.) He stated that it was physically possible to produce a well below 50 pounds, and physically they might be produced to zero pounds but that such operations would not be justified economically. (Vol. LXXXVIII, p. 13217.)

The witness' calculations are made upon a value of gas at the well of 4c per Mcf. on a 16.4 pound pressure base. This is the prevailing price in the field and is based upon the amount that is paid generally by producing companies to their royalty owners for the royalty gas. It hasn't fluctuated particularly during the past few years. (Vol. LXXX-

VIII, pp. 13218-13220.) He has assumed that the present value will remain the same until the abandonment pressure of 50 pounds has been reached. He sees no reason for the value of gas to increase particularly in the future. (Vol. LXXXVIII, pp. 13230, 13231.)

His computation is also based upon the fact that wells in the state of Texas are not permitted to produce in excess of 25% of their open flow. He has assumed that this limitation will also continue throughout the period covered by this study. There is no provision in the law for increasing the proportion of the open flow that a well might produce when pressures become low. It is the witness' opinion in any event that no operator should produce a well in excess of 25% of its open flow volume and that this is particularly true when low pressures have been reached for the reason that there is a great deal of difficulty producing wells at low pressures without overproducing them. (Vol. LXXXVIII, pp. 13234-13236.)

The witness further testified that it would be natural to conclude that if regulations permitted the production of a well up to 50% of its open flow, it would be possible to produce under those circumstances twice as much gas as would be produced if the restriction was 25% of its open flow as it is today, but that this would be an absurd assumption for the reason that no well should be produced at the rate of 50% of its open flow, regardless of regulation. (Vol. LXXXVIII, pp. 13237, 13238.)

The witness also reiterated that open flows will decline at a faster rate than that indicated by the back pressure curve. This is true by reason of mechanical failures of the well. That is, the salting of the formation or caving, or mudding off of the formation. This does not discredit the back pressure curve. The curve will apply if there is no change in the well bore, but if something happens to the well which will decrease its producing characteristic the curve will not apply. Canadian has already had several mechanical difficulties and in some instances has been unsuccessful in restoring a well to its original open flow. (Vol. LXXXVIII, pp. 13244-13250.)

The witness testified that even if the value of gas at the

mouth of the well became higher than 4c per Mcf. during the period covered by the study, that still he did not believe that wells would be produced below a 50-pound pressure. If gas advanced to 8c at the well this would not mean that the wells would be produced down to 25 pounds. The computations, although based upon 4c per Mcf. for the gas at the well would not provide enough money to pay the cost of operations. The witness had not considered anything at all for return on the investment at the 4c per Mcf. wellhead price. (Vol. LXXXVIII, pp. 13252-13255.)

The witness reiterated that at a 50-pound pressure and a 65 per cent load factor, an average well could be expected to produce 160 Mcf. per day, which volume valued at 4c per Mcf. at the well amounts to approximately $6.50 per day, or approximately $2,375 per year before deductions for royalties and severance taxes. Royalties and severance taxes at the present time and at the average rates, amount to approximately $595 per year. This leaves, therefor, the net sum of $1780 available for operating and maintaining an average well at 50 pounds rock pressure. The operating costs alone, without providing for anything else, have been in excess of $1780 per year; for example in 1933 the operating cost of an average well was $2,661.35; in 1934 it was $2,741.58; in 1935 it was $2,477.53; in 1936 it was $2,146.14; in 1937 it was $2,287.81; in 1938 it was $2,173.65; in 1939 it was $2,291.50, and in 1940 it was $2,072.56. (Vol. LXXXVIII, pp. 13265-13267.)

The witness stated in his direct examination:

> "The past and present costs of Canadian River Gas Company for operating and maintaining its producing gas wells do not provide a dependable index for the purpose of measuring the cost of operating and maintaining such wells when they reach rock pressures as low as 50 pounds. Present wells of Canadian River Gas Company have been operating at comparatively high pressures, and therefore, have been free from many operating difficulties which will develop at lower pressures. As the rock pressure of a well decreases, its open flow decreases at a proportionately higher rate. As the open flow decreases, the well is less capable of keeping

itself clean of cavings and free from water, which has a tendency to increase bridging in the hole, flooding and salting in the formation. Moreover, as the wells approach a 50-pound rock pressure, they will be older and the corrosion of casing by water at the formations in which the well is not producing will became a greater problem. Since a well of low open flow capacity is unable to free itself of its accumulated water, it may be necessary in many instances to pump or syphon off such water which will add substantially to the cost of operating and maintaining the wells." (Vol. LXXXVI, pp. 13039, 13040.)

Remaining Life of Texas Panhandle Field as a Source of Supply for Long Distance Pipe Lines

Testimony of R. W. Hendee, Witness for Canadian

R. W. Hendee, who is an engineer and also General Manager of Canadian and whose qualifications have been given heretofore, computed the remaining life of the Texas Panhandle Field.

Hendee's testimony on direct examination is shown in Volume LXXXVI, pp. 13045 to 13049, and in Exhibit 255 at pages 1 to 4 inclusive.

He stated that the probable life of the Texas Panhandle Field as a source of supply for major long distance pipe lines now taking gas from that field depends upon (a) the total recoverable gas reserves, (b) the rate of withdrawal, (c) the rock pressure at which it will become unprofitable to drill additional gas wells in the Texas Panhandle Field in the future, and (d) the abandonment pressure below which it will be unprofitable to operate and maintain the then existing gas wells.

For the purposes of his study, he adopted:

(a) J. D. Thompson Jr.'s estimate of original gas reserves in the field as shown in his Exhibit No. 207;

(b) C. J. Peterson's cumulative past withdrawal figures from the field as shown in his Exhibits Nos. 206 and 206-A for the full period ended December 31, 1940;

(c) Max K. Watson's study of rock pressure at which it will become unprofitable to drill additional gas wells in the Texas Panhandle Field in the future, and

(d) Max K. Watson's abandonment rock pressure of 50 pounds as shown in his Exhibit No. 254.

Estimates of future withdrawals beyond 1940 have been made by the witness, using the same classifications as followed by Peterson, i. e., "Gas Used by Gas Pipe Lines," "Gas Used by Gasoline Plant," "Casinghead Gas Not Treated (Blown in Air)" and "Gas Blown in Air and Used in Drilling Wells," a schedule of the estimated future withdrawals by years together with Peterson's withdrawals being attached to Exhibit 255 as Table I.

With respect to "Gas Used by Gas Pipe Lines," figures were obtained by witness directly from each major pipe line company withdrawing gas from the field.

With respect to "Gas Used by Gasoline Plants" (which includes gas used for the manufacture of carbon black), a study has been made by the witness of the probable trend of operations in the Texas Panhandle Field of the natural gasoline industry and the carbon black industry, and from the information and data gathered in such study the withdrawals of gas for such purposes have been estimated by him for the future.

Studies and estimates have been made by him with respect to "Casinghead Gas Not Treated (Blown in Air)" and "Gas Blown in Air and Used in Drilling Wells."

There is attached to Hendee's Exhibit 255 a production table which is set out in full as follows:

Year	Gas Used By Pipe Lines M.C.F. (1)	Gas Used By Gasoline Plants M.C.F. (2)	Casinghead Gas Not Treated (Blown in Air) M.C.F. (3)	Gas Blown in Air and Used in Drilling Wells M.C.F. (4)	Total Gas Produced M.C.F. (5)	Total Cumulative Gas Produced M.C.F. (6)
1926 and earlier	15,725,533	34,300,000	92,000,000	105,400,000	247,425,533	247,425,533
1927	8,825,598	263,800,000	144,000,000	88,600,000	505,225,598	752,651,131
1928	39,978,176	330,500,000	114,000,000	49,500,000	533,978,176	1,286,629,307
1929	84,767,509	395,110,000	90,000,000	55,800,000	625,677,509	1,912,306,816
1930	81,175,878	412,796,000	70,000,000	52,600,000	616,571,878	2,528,878,694
1931	86,538,708	346,255,000	50,000,000	16,300,000	499,093,708	3,027,972,402
1932	97,087,294	283,708,708	32,940,000	4,026,000	417,762,002	3,445,734,404
1933	109,179,977	333,838,516	25,550,000	4,380,000	472,948,493	3,918,682,897
1934	147,363,215	564,804,621	33,800,000	21,665,125	767,632,961	4,686,315,858
1935	156,695,751	563,734,998	28,850,000	26,037,265	775,318,014	5,461,633,872
1936	183,804,643	330,269,607	15,540,000	30,066,628	559,680,878	6,021,314,750
1937	210,333,095	345,298,466	6,205,000	29,692,496	591,529,057	6,612,843,807
1938	207,553,695	318,498,051	5,075,000	12,268,267	543,395,013	7,156,238,820
1939	222,299,905	329,653,273	7,300,000	13,026,239	572,279,417	7,728,518,237
1940	235,860,805	337,256,848	7,320,000	17,029,475	597,467,129	8,325,985,366
1941	239,538,447	340,000,000	7,300,000	15,000,000	601,838,447	8,927,823,813
1942	257,242,137	345,000,000	7,300,000	15,000,000	624,542,137	9,552,365,950
1943	269,210,846	345,000,000	7,300,000	15,000,000	636,510,846	10,188,876,796
1944	282,697,341	345,000,000	7,300,000	15,000,000	649,997,341	10,838,874,137
1945	291,972,410	345,000,000	7,300,000	15,000,000	659,272,410	11,498,346,547

(The volumes shown above are computed on a pressure base of 16.4 pounds per square inch.)

The above table shows the actual withdrawals from the field as compiled and estimated by Peterson and shown in his Exhibits 206 and 206-A through the year 1940. This table also shows the estimates of future production by Hendee for the years 1941 to 1945 inclusive. Hendee assumes that the production from 1945 to 1956 will be the same on the average as the production in the year 1945, as estimated by him. It will be noted that Hendee estimates that the total production from the field in 1945 will be about 62 billion greater than the total production from the field in 1940, an increase of slightly over 10%. Most of this increase results from the increase in withdrawals by pipe lines which accounts for approximately 56 billion from 1940 to 1945 out of a total overall increase of 62 billion for the same period. In other words, Hendee's estimates anticipates practically no increase in the withdrawals from the Panhandle Field except the increase in withdrawals by the pipe line companies.

Hendee stated that the annual actual and estimated withdrawals had been combined in cumulative totals and then plotted against Thompson's estimated total recoverable gas reserves on a curve entitled "Total Cumulative Past and Estimated Future Withdrawals from Texas Panhandle Field," which is attached to Exhibit 255 as Chart "A." Since no estimates covering future withdrawals beyond the year 1945 were made; the plotted curve was extended beyond 1945 at approximately the 1945 withdrawal rate until the curve intercepted Thompson's estimated recoverable gas reserves at a rock pressure of 100 pounds.

Watson has shown in his Exhibit No. 254 that it will be unprofitable to drill gas wells in the Texas Panhandle Field with rock pressures of 125 pounds or less. Therefore, it is reasonable to expect that drilling of new wells in the field will have ceased when the average field pressure has declined to 100 pounds. Watson has also shown in his Exhibit No. 254 that commercial production of gas by the major pipe line companies will cease when the average field pressure has declined to 50 pounds. Since it is assumed that drilling will cease at an average field pressure of 100 pounds, it follows that the productive capacity of existing wells will decline progressively down to the assumed abandonment pressure which results in declining annual withdrawals for this period as indicated on the plotted curve

By applying in this manner the past and estimated future gas withdrawals against Thompson's recoverable gas reserves in the field, the curve which witness had plotted indicated that average field pressures will have reached Watson's abandonment pressure of 50 pounds and the economic life of the field as a source of supply for major long distance gas pipe lines will terminate by the end of the year 1956.

There is attached to Exhibit 255 a curve showing the total cumulated past and estimated future withdrawals from Texas Panhandle Field. This curve shows that when an average pressure of 100 pounds has been reached in the field that there will have been produced a total in excess of 15 trillion cubic feet of gas based upon Thompson's estimate as contained in Exhibit 207, and that when an average pressure of 50 pounds has been reached the total production from the field will be 17,381,014,589 Mcf. on a 16.4 pounds pressure base. This corresponds to Thompson's estimate of original gas in place at an assumed abandonment pressure of 50 pounds per square inch gauge but before the application of Thompson's recovery factor of 90 per cent.

Hendee testified on cross examination that he began collecting information for his Exhibit 255 in January, 1940, although he had been generally familiar with production in the Texas Panhandle Field for the past twenty years and particularly familiar with the question since assuming his present position about five years ago. (Vol. LXXXVIII, p. 13287.) He estimated the production from 1940 to 1945 and used the 1945 estimated production figure for the remainder of the period covered by his study, that is, up to 1956, at which time the average field pressures will have reached an abandonment pressure of 50 pounds and the economic life of the field as a source of supply for major long distance gas pipe lines will expire at that time. The witness has estimated that the withdrawals will continue at the same rate as the 1945 estimated withdrawals until the curve shown in Exhibit 255 intersects the 100-pound reserve estimate of Thompson and that the withdrawals will be tapered off somewhat until the 50-pound abandonment pressure has been reached. (Vol. LXXXVIII, pp. 13288, 13289.)

The witness was accused of having testified on a previous

occasion in this case that the life of the Canadian River-Colorado Interstate project would terminate in 1947, which is the date that most of the contracts expire. He stated positively that he didn't testify to that effect but merely testified that he didn't know what would happen after the contracts expired in 1947. (Vol. LXXXVIII, pp. 13289, 13290.)

In this Exhibit 255 the witness considered the withdrawals from the entire field and didn't consider the withdrawals of Canadian alone for the reason that the life of Canadian as a gas producer is dependent generally on the life of the field, and that his study had to do primarily with the life of major long distance gas pipe lines. (Vol. LXXXVIII, pp. 13291, 13292, 13294.) There will be some gas produced after the long distance pipe lines are no longer operating in the field. This gas will be utilized locally. (Vol. LXXXVIII, p. 13295.)

The witness has assumed that gas withdrawals will remain about the same from 1945 to 1956. However, the general trend of withdrawals has been upward, but he has given no consideration to this in determining the future life of the field. (Vol. LXXXVIII, pp. 13300, 13301.) The witness has had some experience in estimating future withdrawals and in fact had estimated the 1940 production and had missed it only one-tenth of 1 per cent. (Vol. LXXXVIII, pp. 13301, 13302.)

In estimating the future withdrawals of the pipe line companies operating in the field he simply took the estimates of the executives of the various companies. In other words, he utilized the estimates of the respective companies as to their future withdrawals for 1940 to 1945. (Vol. LXXXVIII, pp. 13303, 13304, 13305, 13331.)

In estimating the withdrawals by gasoline plants the witness made a particular study of the gasoline industry, the carbon black industry and related industries. This study was based primarily upon the Minerals Year-Book issued by the Bureau of Mines and he also studied the past production or withdrawals of the gasoline plants and carbon black plants in the field. The withdrawals for these purposes have been fairly constant for the past few years except for the years 1934 and 1935 when the Stripping Law

was in effect. After that, and beginning in 1930, the withdrawal figures have been fairly constant. No two years have been actually the same but he would not expect them to be. The witness also discussed the matter generally with a great many people and read numerous articles dealing with gasoline plants, carbon black plants and pipe lines. He didn't write to the executives of companies owning gasoline plants as he did to the companies owning gas pipe lines for the reason that the gasoline plants were running at about their capacity and it would follow that their production for the future would not vary a great deal from the production at present although the general condition in the industry indicates that the production of both carbon black and gasoline will continue to increase. (Vol. LXXXVIII, pp. 13334-13343.) Reference to the table of gas withdrawals incorporated in Exhibit 255 will show that after 1941 the witness makes no change whatever in the estimated use of gas by gasoline plants and upon being questioned concerning this he stated that this represented a very fair average figure for the future and that he didn't think it would be much more or less than that. (Vol. LXXXVIII, p. 13345.)

His estimates for casinghead gas not treated and blown in the air are virtually the same from 1938 for the reason that the witness feels that the wastage of gas of this character is about as low as it can possibly get. There was a great decrease in gas of this character blown into the air from 1934 to 1937 due to more careful operations on the part of the operators in the field but he doesn't think it is possible for it to get any lower than it is now. (Vol. LXXXVIII, pp. 13345-13346.)

The witness is also of the opinion that gas lost in the drilling of wells and gas blown into the air is about as low as it can get. The figures in 1932 and 1933 are very low because there wasn't much drilling during that period and from 1933 to 1937 there was an intensive development which caused the curve to go up. There has been quite a little drilling from 1938 to 1940 but the loss of gas has been better controlled through the utilization of better methods. (Vol. LXXXVIII, p. 13348.)

The curve, as shown in Exhibit 255, tapers off somewhat from the 100 pounds average pressure point to 50 pounds average pressure. That is true because the production will

be a little less during that period, and if he had not tapered off the production during that period, his calculations would have resulted in reaching an abandonment pressure at 50 pounds about two years sooner than his curve indicates. The witness explained that it was perfectly obvious where drilling is discontinued at a pressure of around 100 pounds you will get less and less production from the same wells as the pressure declines. (Vol. LXXXVIII, pp. 13349, 13350.)

The witness testified on redirect examination that he did not estimate the future withdrawals by the gas pipe line companies by extending a curve based upon past performance, but merely took the estimated future withdrawals as given to him by the various companies. If he had made the estimate independent of the figures given to him by such companies it would have been necessary for him to study the markets of the companies, the market outlets and matters of that kind. It would have been necessary for him to have had a great deal more information than is reflected by past sales. (Vol. LXXXVIII, pp. 13352, 13353.)

The principal outlet of gas consumed by gasoline plants is the outlet afforded by carbon black plants. There is nothing at this time that indicates any decrease in the manufacture of carbon black. About 85% of carbon black production is utilized in the rubber industry and this production of rubber in the United States is increasing and will probably continue to increase by reason of the demands brought about by the fact that army units are being mechanized. Carbon black is also used in synthetic rubber to the same degree as it is in natural rubber and the manufacture of synthetic rubber is likely to increase in the immediate future. The demand for motor fuel also affects to some degree the operation of gasoline plants and the present indications are that there will be a tremendous demand for gasoline. The witness, however, in estimating the demands of gasoline plants has not taken this increased demand into account but has assumed that the gasoline plants and carbon black plants will consume the same volume of gas in the future that they have in the past. (Vol. LXXXVIII, pp. 13353, 13355.)

The witness further testified on recross examination that the utilization of sour gas for the manufacture of carbon

black is not necessarily wasteful. Carbon black is a very useful product and is the very best substance *than* can be used in automobile tires in order to increase longevity of the tire and its grip on the road. It is not wasteful to take the gasoline out of the gas since but a very, very small percentage of the gas is lost and it is really an improvement upon the gas that goes in the pipe lines. It really doesn't hurt the gas enough to be of any particular importance. The witness does not know whether the pipe line companies will in the future take sour gas or not but if they do he does not believe that this will materially affect the life of the field since the use of the sour gas for this purpose would merely replace the gas that is now being used for other purposes and the total withdrawals would be about the same. (Vol. LXXXVIII, pp. 13357, 13362, 13364, 13365.)

R. W. Hendee further testified on cross examination (Vol. 88, pp. 13286-13298; 13309; 13332-13333, and in Vol. 101, pp. 15635-15637) as follows:

Q. Mr. Hendee, your study is predicated upon the soundness of the testimony of three witnesses?

A. Three.

Q. Mr. J. D. Thompson, Jr's. estimate of reserves; C. J. Peterson's cumulative withdrawals and Max K. Watson's study of rock pressure; if you are wrong, they are wrong?

A. That would be correct.

Q. You made a careful study of their exhibits?

A. Yes, I have.

Q. Do you feel competent to pass upon the soundness of their exhibits?

A. No, I don't as I am not a geologist. I have used the exhibits as the best information that I had.

Q. Why didn't you take Mr. Hammer's exhibit, his estimate of reserves, and use it here?

A. Because I prepared this before Mr. Hammer's exhibit was put in in the first place.

Q. You mean if you had been working for the Federal Power Commission you might have done that?

A. I might have.

Q. Now, this study of yours as to future withdrawals in the Texas Panhandle field, how long did it take you to get this information together?

A. I started in January 1940, I believe, collecting the information.

Q. January 1940?

A. That is right.

Q. This is the first sort of study like this you have ever made?

A. Exactly like this, yes.

Q. Have you spent many years studying the withdrawals from the Panhandle Field of Texas?

A. I didn't get your question.

Q. Have you spent many years studying the rates of withdrawals from the Texas Panhandle field?

A. No.

Q. You just cumulated a lot of data and put it together and here it is?

A. No, I wouldn't say that. I have had general experience in the gas business for twenty years and that has naturally been a subject of my interest for a good many years. I have been interested in the Panhandle field, although I have only been in my present position about five years.

Q. During that five-year period, however, you have made no study as to the withdrawals from the field?

A. No, I don't think I have.

Q. And is this study made specifically for this case or not?

A. It was made specifically for this case.

Q. Is your company relying upon this exhibit to govern its future conduct in the operations of your company?

A. I think so, yes, sir.

Q. You think they are?

A. Yes.

Q. What makes you believe that?

A. Well, I think that is the best information we have at the present.

Q. At the present?

A. Yes, sir.

Q. Do you think it is a good indication of what will be the situation in 1956?

A. I think this is an estimate and I think it is the best estimate we can make and the best one available at the time.

Q. As I understand, you don't make an estimate all the way to 1956 but just to 1945?

A. That is correct.

Q. What happens with your 1956 proposition here? You state here at the end of your exhibit: "The curve which I have plotted indicates that average field pressures will have reached Mr. Watson's abandonment pressure of 50 pounds and the economic life of the field as a source of supply for major long distance gas pipe lines will terminate by the end of the year 1956."

A. Where are you reading?

Q. On the last page of your written statement.

The Trial Examiner: It is Page 4, Mr. Hendee.

The Witness: What was the question?

By Mr. March:

Q. My question is, if you have just made your estimate to 1945, how can you make this statement about 1956?

A. I have assumed for the purpose of this exhibit that the withdrawals will continue at the same rate until the curve intersects Mr. Thompson's 100-pound reserve and it has been tapered off to the 50-pound line. That is all there has been done.

Q. So your real estimate is 1945 and you have just extended your curve to 1956 just to see what it would look like?

A. That is correct.

Q. Now, I thought that you had already testified here that this whole project is going to blow up like a balloon in 1947 when this contract expires with the Colorado Interstate Gas Company:

A. I didn't testify that way. I said that I didn't know about it beyond that time.

Q. Since you have had time to think it over, what position are you taking now relative to the—what will happen at the time the contract with the Colorado Interstate Gas Company and Canadian River Gas Company expires in 1947?

Mr. Keffer: If the Examiner please, the exhibit of Mr. Hendee's is a field-wide study. It isn't a study limited to Colorado Interstate Gas Company and Canadian River Gas Company particularly, as it is an estimate of the withdrawals from the field as a whole and not withdrawals by Canadian River Gas Company.

When I say "withdrawals from the field," I mean by all of the operators in the field over this period; applying that, then, to Mr. Thompson's estimate of reserves, it is a very simple calculation to ascertain how long that field will last at that withdrawal. Except to the extent it includes Canadian River's withdrawals—I will state it that way—it has nothing to do specifically with the particular volume of Canadian River wells withdrawals but the aggregate of all of the company's wells in the field.

Mr. Keffer: I think your question there, Mr. March, goes somewhat beyond the exhibit in that respect.

Mr. March: He comes up with one exhibit in which he ends everything in 1947 and now he has an exhibit in which he takes it on up beyond that period. I wanted to know—

Mr. Keffer: I understand what you mean.

Mr. March: —what he considers to be the life of the property; whether it considers the property to be the life of the contract or the life of the field.

Mr. Keffer: I don't see how the life of the contract would have anything to do with the life of the property as such. He may be out of business but still have some gas left.

Mr. Spencer: Mr. Examiner, the point is this: Mr. Hendee is not purporting to show nor is he submitting any estimate of the life of the Canadian River Gas Company's reserves in relation to its market in this exhibit.

Mr. March: I don't think Mr. Hendee will make that statement, Mr. Spencer. I will ask him.

Q. Mr. Hendee, has this anything to do with the life of the Canadian River Gas Company's reserves you have available?

A. This particular exhibit?

Q. Yes.

A. No.

Q. I thought you stated in this exhibit that the Canadian River Gas Company's life as a gas producer and a seller of gas was dependent upon the life of the field.

A. That is true generally, yes.

Q. That is the point and that is why you had to consider the withdrawals from the entire field?

A. Yes.

Q. That instead of considering the Canadian River's withdrawals?

A. Yes.

Mr. Spencer: I guess I didn't go far enough with what I meant. What I meant to say is, it is quite possible Canadian River Gas Company would be out of business in 1947; that the properties would be sold to somebody else and operated by somebody else, but as a project he has not attempted to fix the life of that project in this particular exhibit. It is based entirely on the field, and total withdrawals on that field.

Mr. March: Is there an objection pending?

The Trial Examiner: I don't believe so.

Mr. Spencer: I don't believe there is an objection.

By Mr. March:

Q. You used the words "economic life" here of the field. What do you mean by the word "economic"?

A: Well, that, as Mr. Watson described it, is a point below which it wouldn't be economical to produce or to continue the drilling of wells, and 50 pounds is the point at which it would not be economical for long distance pipe lines to continue taking gas from the field.

Q. I see, Mr. Hendee, that you have been more conservative in this statement than Mr. Watson was in his statement. He stated, as I understand, in his exhibit: "Fifty pounds is the rock pressure at which it will become unprofitable for Canadian River to continue operating and maintaining its gas well from the Texas Panhandle field," and you state in effect it will be unprofitable for it to continue in the use of long distance gas pipe lines.

A. That is correct; that is what I said.

Mr. Spencer: He hasn't said that. Let's read exactly what he said. There is a difference in there.

Mr. March: Let's do that. He states: "The curve which I have plotted indicates that average field pressures

will have reached Mr. Watson's abandonment pressure of 50 pounds and the economic life of the field as a source of supply for major long distance gas pipe lines will terminate by the end of 1956," and Mr. Watson has indicated that when the pressures of 50 pounds are reached by the Canadian River Gas Company that it will be no longer profitable for them to continue operating and maintaining its gas wells in the Texas Panhandle field.

Mr. Spencer: The question that you asked him had particular relation to his statement on Page 3, the first two sentences, in the paragraph commencing on that page.

Mr. March: Page 3 of Mr. Watson exhibit?

Mr. Spencer: No.

Mr. March: I was reading from the last page of the written statement of Mr. Hendee.

Mr. Spencer: I don't want to mix up your cross examination, Mr. March.

Mr. March: He has already answered my questions.

Q. Well, Mr. Hendee, since you have been more conservative than Mr. Watson, what basis have you to make your assertion in effect that the wells will be only available for gas pipe lines?

A. Did you have the word "Canadian" in there?

Q. No.

A. The only thing I studied was the field as a whole and I feel that is true. I am considering major long distance gas pipe lines. There will be production from the field, as Mr. Watson says, after that.

Q. You haven't made any study of the economic abandonment pressure study of the field?

A. No, sir.

Q. You have had to take Mr. Watson's data on that?

A. That is right.

Q. And Mr. Watson says when the Canadian River wells reach 50 pounds it will be no longer profitable to operate at all. What I want to know is why you didn't follow his conclusions there.

A. I consider the Canadian River a major long distance pipe line.

Q. You imply on Page 4 of the statement that the Canadian River Gas Company will be able to utilize the gas locally from these wells?

A. That may be so.

Q. That is very likely, isn't it?

A. Very likely. There will be lots of gas produced after that.

Q. That is very likely.

A. Yes.

Q. There will be lots of gas produced after you get 50 pounds abandonment pressure?

A. Yes.

Q. Do you know of any fields from which that statement can be supported?

A. You mean lots of gas produced below fifty pounds?

Q. Yes.

A. Yes, sir.

Q. Where, for example?

A. Fields in Oklahoma that have gone down to zero pounds but—

Q. Zero pounds?

A. But at considerable expense and trouble.

Q. How did they pull them down to zero pounds?

A. Pardon me?

Q. How did they pull them down to zero pounds?

A. With compressors on a suction.

Q. The company you were formerly with, did it have any such wells?

A. Yes.

Q. Where did they distribute their gas?

A. That was for very very local distribution.

Q. Where does that company have its major outlets?

A. Tulsa and Oklahoma City.

Q. That is as far as they transport the gas?

A. Yes, sir, that is the greatest distance.

Q. How far is the gas from Tulsa?

A. This gas wasn't going into Tulsa.

Q. How far is the field from Tulsa from which you were withdrawing your gas?

Mr. Spencer: You mean by suction?

The Witness: This gas I was talking about didn't go

to Tulsa. Tulsa was drawing its gas—the gas was being drawn 150 to 200 miles from Tulsa.

By Mr. March:

Q. Well, was it all in that same field?

A. No, the Oklahoma Natural Gas Company had about 30 or 35 fields it was drawing gas from.

Q. How far was this field from which the gas was being drawn to zero from Tulsa?

A. The field was about 35 miles from Tulsa.

Q. Where were they delivering their gas?

A. The gas was going right around the town of Claremore. The wells were around the town of Claremore.

Q. And this field from which Tulsa secures its gas is 150 or 200 miles away? What are the pressures in the field?

A. What is that?

Q. What are the pressures in the field from which Tulsa is securing its gas?

A. It was five or six hundred pounds when I left there.

Q. Have you any other citations you can support gas being produced down to zero?

A. No, not directly.

Q. It usually goes below zero?

A. No, a gas field as such doesn't generally go below zero.

Q. Have you ever heard of them going below zero?

A. Pardon me?

Q. Have you ever heard of any gas field having wells pulled down below zero?

A. Dry gas wells—no, I don't think so.

Q. How about sour gas wells?

A. Casinghead gas is drawn below zero. That is for gasoline plants.

The Trial Examiner: Mr. Hendee, did the Oklahoma Natural Gas Company own the distribution system at the town of Claremore?

The Witness: Yes.

The Trial Examiner: And this gas went directly into this distribution system?

The Witness: Yes.

The Trial Examiner: It is still going, in so far as you know?

The Witness: I don't think it is as most of the wells have been pulled down and abandoned.

By Mr. March:

Q. At what pressure were they when they were abandoned?

A. Down to 25 or 30 pounds, and various pressures.

Q. You said some of the wells were down to zero?

A. No, they were pulled down to zero by the suction.

Q. Pulled down to zero and they were forced to let the pressures build back up?

A. Yes.

Q. You could still pull them down to zero?

A. Little wells you could.

Q. It is sort of like milking a cow.

A. That is right, the same principle.

* * * * *

Q. Mr. Hendee, when you made inquiries of these natural gas pipe line companies, did you tell them you wanted the information for rate case purposes?

A. I think I did.

Q. First you sent a letter around to them and next you wired them?

A. Yes.

Q. Then did you get some of them on the telephone?

A. No, I don't think I did, except Mr. Dickinson.

Q. Did you call Mr. Dickinson on the telephone for Texoma Natural Gas Company?

A. Yes.

Q. What about the Phillips Petroleum Company? Don't they produce a little gas?

A. They don't have a pipe line out of the field.

Q. They produce some gas, don't they?

A. Yes.

Q. How does its gas production compare with the rest of the gas production in the field?

A. I really don't know because it goes into various outlets.

Q. You really haven't given that any consideration in this study?

A. It is in here, this cumulative curve.

Q. How did you get it in there when you didn't know about it?

A. I know it is in there because all of the figures are in there.

Q. How do you know the future figures are in the curve when you say you didn't get the future figures from the Phillips Petroleum Company?

A. They are in here in one of the companies' takes or the gasoline figures, so they are continued into the future the same way.

Q. Did you send a letter of solicitation to the Phillips Petroleum Company?

A. No, I didn't.

Q. Why didn't you?

A. I wasn't interested in them particularly as I was interested in the actual take from that field.

Q. You were equally interested in withdrawals from the field?

A. That is true.

Q. Don't you know these other companies take more gas from the field than the pipe line companies?

A. Yes, and they are in here.

Q. You didn't attempt to get any information at all from the Phillips Petroleum Company?

A. No, sir.

* * * * *

Q. Did you ever see that proration schedule of the Canadian River Gas Company before, Exhibit No. 32?

A. I can't identify this exhibit as the exact one.

Q. Do you know this man W. C. Doughty?

A. Yes, sir.

Q. Is he one of your employes?

A. Yes, sir.

Q. Now, are you familiar with the proration schedule of the Canadian River Gas Company?

A. Yes.

Q. Was that a schedule which was just made up by the company itself voluntarily?

A. Yes, that's right.

Q. Was there any written contracts between the lessors and the company approving the proration schedules?

A. No, not that I know of.
Q. Is the schedule subject to change at any time without any notice to the lessors?
A. Yes.

The Trial Examiner: Hasn't Mr. Watson testified as to all of that, Mr. March?

Mr. March: Not clearly. It's not clear. I want to be sure about it. It's not clear. It is now, though.

Now, just one other question:

Q. Is this the first proration schedule the company has ever invoked?
A. This particular one?
Q. Yes.
A. Oh, no. That schedule is changed from time to time.
Q. When was the last time you changed it?
A. It might change from month to month.
Q. It might change from day to day?
A. Yes.

Redirect Examination.

By Mr. Keffer:

Q. You say it is changing from time to time. You are speaking of wells drilled, for example, on acreage that had not therefore been under production?
A. That's right. When a new well is drilled it increases the proven operated acreage under that particular lease and that changes the schedule.
Q. You stated also, Mr. Hendee, that there was no contracts of land owners approving that schedule. You do have certain contracts, such as the Bivins A Consolidated lease, which provides for methods of allocating production to that land?
A. That's true.
Q. And some others in your consolidation lease forms?
A. That's true.

Testimony of J. G. Dickinson, Witness for Commission.

J. G. Dickinson, witness for the Commission, stated that he was General Superintendent of Production for Tex-

oma Natural Gas Company; that he had no connection in any way with Canadian. (Vol. LXIV, pp. 9197-9198.) That all of the gas for the Natural Gas Pipe Line Company of America is furnished from the acreage of Canadian and Texoma Natural Gas Company. (Vol. LXIV, pp. 9202-9203.)

Dickinson testified on cross-examination that his duties as General Superintendent of Texoma Natural Gas Company consisted of supervision of the activities of the geologist, land, lease and production departments, which covers practically all of the field operations of the company and that he had held this position since 1930. (Vol. LXIV, p. 9228.)

The witness testified on redirect examination that it was his opinion that the entire life of the reserves of both Canadian and Texoma Natural Gas Company was approximately twelve years from January 1, 1940, and that his company relied upon this estimate as to the life of the reserves and that this assumed that there would be no pipe line property in service by the end of 1952. (Vol. LXIV, p. 9232.)

J. G. DICKINSON further testified on cross examination (Vol. 64, pp. 9197-9208; 9213-9216; 9218-9226) as follows:

J. G. DICKINSON called as a witness by and on behalf of the Federal Power Commission, being first duly sworn, was examined and testified as follows:

Direct Examination.

By Mr. March:

Q. Please state your name.

A. J. G. Dickinson.

Q. What business are you engaged in?

A. I am General Superintendent of production for Texoma Natural Gas Company.

Q. Are you the same Mr. Dickinson that has been sitting in the court room here the last three or four days?

A. I believe so.

Q. Are you in any way connected with Canadian River Gas Company?

A. No, sir.

Q. Your business here is solely that of an observer?

A. That is right.

Q. Mr. Dickinson, I hand you a copy of a letter here signed by you, addressed to Mr. Robert W. Hendee, dated November 18, 1940, which purports to give the requirements of the Texoma Natural Gas Company on the Canadian River Gas Company for the future. Does that look like the letter you wrote?

A. Yes, I think so.

Q. Are the figures—is that the way you had them?

A. I don't recall the figures but—

Q. Will you state briefly what that shows?

A. This is a designation of quantities of gas which Natural Gas Pipeline Company would require from Canadian River Gas Company to supply markets which would be served by certain extensions which were contemplated.

Q. You say that certain extensions of the Natural Gas Pipeline facilities were contemplated?

A. Yes.

Q. With what certainty do you know that you will require this gas in the future as you have indicated here in this letter from the Canadian River Gas Company?

A. I don't believe I am in a position to testify as to that. Maybe I could best explain this letter by saying that I was advised by Mr. Floyd C. Brown who is vice president and general manger of our company—

Q. Which company is that?

A. The Texoma Natural Gas Company and Natural Gas Pipeline Company.

—that Texoma would be required to furnish certain quantities of gas for additional markets and at the same time he requested that I advise Mr. Hendee that additional quanities would be required from the Canadian River Gas Company—from the Colorado Interstate Gas Company instead of Canadian River Gas Company.

Q. What is Mr. Brown's position? Is he your superior?

A. Yes.

Q. You work under his immediate supervision?

A. No, I work under Mr. Kesinger's immediate supervision.

Q. Who is he?

A. He is general superintendent.

Q. Kesinger works under Mr. Brown's supervision?

A. Yes.

Q. Let's see. You say that you furnished this estimate of future requirements because Mr. Brown told you to?

A. No, I believe it would be more accurate to say that Mr. Hendee asked me to furnish him with the requirements from Colorado Interstate as far as Natural Gas Pipeline Company was concerned, and I requested the information of Mr. Brown.

Q. Well, you asked Mr. Brown to tell you just exactly what the requirements of Texoma Natural Gas Company and Natural Gas Pipeline Company of America would be upon Canadian River Gas Company, is that right?

A. Yes.

Q. So he furnished you with this information in this letter?

A. That's right.

Q. Well, how do you know that these will be the requirements?

A. Well, I am depending upon Mr. Brown's judgment in that matter.

Q. You state here in this letter:

"Confirming my telephonic conversation with you yesterday the following tabulation represents the increased quantities of gas to be furnished pipe line to Chicago and Milwaukee by Canadian River Gas Company."

Now, Mr. Dickinson, do you know whether or not Canadian River Gas Company will be required to furnish the amounts of gas indicated here in this estimate?

A. It is my judgment that they will be, based on the acquirement of knowledge as I outlined just previously.

Q. Then it is not solely the information which you got from Mr. Brown?

A. Not entirely.

Q. If you wrote this letter and state that that is how much gas you are going to require, you merely are relying upon what Mr. Brown said, or did you have some knowledge as to the correctness of these figures yourself?

A. Oh, no, I have no knowledge of the figures outside of the information I got from Mr. Brown.

Q. Did you get all of this information from Mr. Brown, every bit of it?

A. Yes.

Q. So, therefore, you don't know whether or not they are going to need these increased quantities of gas indicated in this letter or not, of your own knowledge—the Texoma Natural Gas Company and the Natural Gas Pipeline Company of America?

A. No, I haven't made a study of market requirements.

Q. As far as you know, they may not need any of it?

A. Oh, I wouldn't say that. I have confidence in Mr. Brown's judgment. I would believe they would probably need all of it.

Q. Let's see how Mr. Brown formulates this judgment. You are the superintendent in charge of production of Texoma Natural Gas Company, is that correct?

A. That's right.

Q. And Texoma Natural Gas Company—what is the relation between Texoma Natural Gas Company and Natural Gas Pipeline Company of America?

A. They are affiliated companies.

Q. They are controlled by identical interests, aren't they?

A. Not exactly.

Q. What is the difference? Wherein are they not controlled by identical interests?

A. Well, I believe that Standard of New Jersey, which does have an interest in Natural Gas Pipeline Company, does not have an interest in Texoma.

Q. That is the only difference in the relationships?

A. I think so.

Q. Are they operated as substantially a single business e terprise?

A. Yes.

Q. Now, when Mr. Brown wants to know whether or not he is going to have to go to some source—strike that, will you?

All of the gas of Natural Gas Pipeline Company of America is furnished by the Texoma Natural Gas Company and the Canadian River Gas Company, is it not?

A. Yes. That is, it is furnished through Colorado Interstate from Canadian River acreage.

Q. Yes.

A. And Texoma acreage.

Q. Those are the only two sources of supply for the Chicago line?

A. Yes.

Q. Well, now, when Mr. Brown wants to know, as to whether or not all of that gas could be supplied by you or not, he would have to ask you as production superintendent, would he not?

A. Yes, I think he would ask me.

Q. Well, did he?

A. Yes, I had a conference with Mr. Brown in Chicago in which we discussed the future requirements from Texoma acreage.

Q. What sort of a report did you make to him?

A. I told him that we had ample reserves in the Panhandle field to supply the additional requirements from Texoma over a considerable number of years.

Q. How many years?

A. I don't recall.

Q. Approximately, how many years?

A. I don't remember that, Mr. March.

Q. Would it be fifty years or twenty years?

A. No.

Q. Would it be twenty years?

A. I don't remember.

Q. Would it be five years? You have some idea, now, don't you, Mr. Dickinson? What did you mean by a large number of years? What did you have in mind when you said "large number of years"?

A. I think it would be best to express it this way, that on account of the drainage condition in the Panhandle field the life of Texoma leases is limited by the life of the field and Texoma has more reserves than is required for its load and that we could furnish additional gas for the extra markets in addition to our present setup, present requirements.

Q. For a good many years?

A. Yes.

Q. About how many years?

A. Well, I told you I didn't remember.

Q. Well, you have some idea, now Mr. Dickinson, now, don't you? Just give us approximately.

A. Well, as I remember it was in the neighborhood of ten years, more or less. I don't remember exactly.

Q. Approximately ten years, you thought, that the Texoma Natural Gas Company had sufficient reserves to fur-

nish their present requirements for approximately ten years, is that right?

A. I think so, more or less. I don't remember exactly there.

Q. This drainage thing, I didn't ask anything about drainage—

Mr. Spencer: He's your witness.

By Mr. March:

Q. What do you know about drainage? Are you a geologist?

A. No.

Q. You don't know anything about drainage, then, do you?

A. I made quite a study of the conditions in the Panhandle field.

Q. Are you responsible for the testimony in the Texoma case that the Texoma Natural Gas Company was losing sixty per cent of their gas by means of drainage?

A. I believe Mr. Peterson testified to that.

Q. Do you think they are losing that much?

A. Yes.

Q. All right, you told Mr.— you wouldn't know the per cent of drainage since you aren't a geologist, would you?

A. No, I have no knowledge as to the percentage I didn't make that study.

Q. So you had this conference with Mr. Brown and you told Mr. Brown that you had reserves to take care of the present requirements, you thought, for a period of ten years, and what else did you tell him? That doesn't get down to these figures yet.

A. I think that is all. I told him I thought we had sufficient reserves to supply those requirements for ten years, more or less. I don't remember the exact period.

Q. All right, then, did he ask you—

A. That is, for our 75 per cent of the pipe line requirements. The other 25 per cent is furnished by Canadian River.

Q. You in effect told him that if they wanted to take care of the Milwaukee market or these extensions, whatever they were, they would have to go some place else to get the gas, is that right, in effect?

A. No, I didn't tell him that. He didn't ask me about that.

Q. Did you indicate to him as to how much you would have to get from Canadian River?

A. No, I assumed that the quantities required through Canadian River would automatically be supplied under the contract.

Q. So you didn't give him any figures at all as to just exactly the requirements that would have to come from Canadian River?

A. No, he gave them to me.

Q. Of course, he had this conference with you first and then he turns around and gives the figures to you?

A. No, I think you misunderstood. This conference took place some time before he gave me these figures here. We had some discussion of approximate quantities, but these definite estimates of quantities were not arrived at until some time later.

Q. Oh, you say you did have some discussion, then, on quantities, that Canadian River would have to supply?

A. No, our discussion of quantities dealt with Texoma to start with.

Q. Yes.

A. And then later I made a request for quantities which both Texoma and Canadian River should furnish and then supplied those to Mr. Hendee.

Q. Yes, you were getting those figures, of course, from Mr. Brown?

A. That's right.

Q. Mr. Dickinson, when you speak of the additional requirements to be caused by circumstances beyond the present markets of Natural Gas Pipeline Company, what do you mean by that?

A. Why, principally a proposed extension into Wisconsin and Milwaukee area.

Q. The Milwaukee area?

A. Yes.

Q. Is there a pipe line running from—I believe you stated that it is just a proposed extension to the Milwaukee area, is that correct?

A. That is right. A pipe line has been built to the Wis-

consin line and right of ways have been bought on into the Milwaukee area.

* * * * *

Q. Well, your knowledge of Natural Gas Pipeline's line to Chicago is not superficial, is it?

A. I have general knowledge of that situation.

Q. Do you know whether or not you could deliver the gas in any additional requirements over that line without building a new line?

A. Yes, I am sure we could not deliver any substantial additional quantities.

Q. Without building a new line paralleling the line?

A. Without making some extensions of our pipe line system, yes.

Q. Well, by extension of the pipe line system, of course—

A. Either building a parallel line or looping the present line to some extent.

Q. Well, if your estimates are correct here you couldn't deliver all the gas that you have ultimately to deliver here without paralleling the line, could you?

A. That is true, and we have already bought rights of way to loop this line and have taken option on the station site for a new compressing station in Moore County and bought a right of way from Moore County up to the Gray County station in Oklahoma.

Q. The Gray County station is your principal compressor station?

A. No, it is the second compressor station after you leave the Panhandle field.

Q. Now, you say that your company has two sources of supply, the Canadian River Gas Company and the Texoma Natural Gas Company, both of which are located in the Panhandle field of Texas?

A. Yes.

Q. How much of the requirements do you expect to get from the Hugoton field?

Mr. Spencer: Excuse me. By "these requirements," do you mean during the period named on that letter?

Mr. March: Yes. I want to know what requirements he is going to get from the Hugoton field.

Q. I am interested to know whether or not it might be

possible to get all the gas they want to get from Canadian River from the Hugoton field. What arrangements have been made to get gas from the Hugoton field, Mr. Dickinson?

A. Well, during the period covered by this letter there have not been any arrangements made.

Q. What period is covered by this letter—to 1946?.

A. Yes.

Q. Mr. Dickinson, do you know whether or not your company has made any arrangements to get any gas from the Hugoton field to take care of its requirements to Milwaukee, or other requirements?

A. No definite arrangements, yet.

Q. There is negotiations being carried on, though?

A. No, it has not reached that stage yet, I don't think.

Q. You know very positively that no negotiations are being carried on or arrangements made with regard to getting gas from the Hugoton field?

A. Oh, I think there has been a lot of conversation, but I don't know whether you would characterize them as negotiations or not.

Q. Have you been making those preliminary conversations and have you been in charge of them?

A. Oh, I have been making some of them.

Q. Where is the Hugoton field in relation to the Texas Panhandle field? How many miles north?

A. I don't remember. Those fields are quite large.

Q. How far is the nearest producing well in the Hugoton field from the nearest producing well in the Panhandle field?

* * * * *

Q. Do you know the answer to my question as to the distance?

A. No, I can't tell you without referring to a map. I don't remember that.

Q. Would you say it was fifty miles—less than fifty miles?

A. I think that from the edge of one field to the edge of another that fifty miles might be all right.

Q. It would be less than that, wouldn't it?

A. I don't remember.

Q. Where is the Hugoton field in relation to your pipe line?

A. It is west of it.

Q. Approximately how far?

A. Oh, forty or fifty miles. I don't remember that distance very well either. That's kind of a hard question to answer, too, because these eastern limits of the field aren't definitely delimited and it is rather irregular. I don't remember that.

Q. How far is your pipe line, approximately, from the nearest producing well in the Hugoton field?

A. I don't know.

Q. Do you know approximately?

A. Yes, it is somewhere around 40 miles, I should say.

Q. It is not over that, is it?

A. I don't think so.

Q. It is less than that?

A. It could be.

Q. How much acreage does your company own in the Hugoton field?

A. Not any.

Q. How much acreage do the companies controlling your company own in the Hugoton field?

A. I don't remember.

Mr. Spencer: Now, again, Mr. Examiner, why is it necessary to go into this as far as any issues involved in our case here?

The Trial Examiner: That's just the point, Mr. March. You said a while ago that you wanted to establish a certain thing and now you are going way beyond that.

Mr. March: No, I want to try to establish here that they can get their requirements from the Hugoton field and wouldn't have to have the requirements from the Canadian River Gas Company.

Mr. Spencer: Why, Mr. March, we could get them from Oklahoma City or Oklahoma or any other field or from Louisiana. Is that a part of the issues in this case?

Mr. March: It makes a lot of difference in the money spent here in the well drilling program and what-not.

The Trial Examiner: Well, it seems to me, Mr. March,

that that is wholly a matter of conjecture of what they might do or what they might not do here.

Mr. March: That's the whole thing. These estimates here are a matter of pure guess.

Mr. Spencer: Why don't you let it go at that, then?

Mr. March: I just want to establish clearly that they are, if I can. If I can't I want the record to clearly show.

Then the Examiner thinks I shouldn't ask any more questions in regard to the Hugoton field in relation to this pipe line?

The Trial Examiner: I don't see how, Mr. March, or I don't see why for the purpose of this proceeding.

Mr. March: I would like to ask one more question:

If the companies controlling Texoma Natural Gas Company and Natural Gas Pipeline Company of America own substantial acreage in the Hugoton field.

Mr. Spencer: That is the same question and I object to it again.

The Trial Examiner: Well, if this witness knows he may state.

By Mr. March:

Q. Mr. Dickinson, do you know as to whether or not the companies which control your company own substantial acreage in the Hugoton field of Kansas?

A. Yes, they do.

Q. Then in conclusion I just want to ask you a couple of questions so that I can get into the record exactly the nature of these requirements which you say Texoma will require of Canadian River. So far as you know of your own knowledge they may not need any gas which is recorded here in this future estimate—your company may not need any of the gas, is that right?

A. No, I wouldn't want to make a statement of that kind. I think I would be willing to say that it is my judgment that they would need these figures.

Q. It is your judgment now that they would need these figures?

A. Yes.

Q. That they would have these requirements?

A. And I am perfectly willing to agree that they are based on Mr. Brown's—based on information which Mr. Brown gave me. Now, that is the extent of my knowledge. I am willing to qualify it to that extent.

Q. That's right. All you know as to these requirements is what Mr. Brown told you?

A. That's right.

Q. And of your own knowledge you don't know whether or not your company will require this gas or not, other than what Mr. Brown tells you?

A. My knowledge has been enhanced by the information which I got from Mr. Brown.

Q. And that is the only enhancement that you have got?

A. That is correct.

Q. Therefore, I want you to answer my question if you can: Of your own knowledge, you don't know whether your company will need any of this gas for the Milwaukee market?

A. I think I have answered the question.

Q. Will you answer that question directly so I can have it in the record yes or no? You can refuse to answer it.

A. I think that I am reasonably—I have confidence in Mr. Brown's estimate here. I think these are the quantities that will be required, and my knowledge is limited by the information furnished me by Mr. Brown.

Mr. March: Read the question to him there. I want to get a little more definite answer on that.

(The question referred to was read by the reporter, as set forth above.)

Mr. Spencer: Now, Mr. Examiner, he is coercing his own witness here. That's a very bad practice.

Mr. March: Sometimes I think that this witness is not my witness but it is Mr. Spencer's witness. He has been over on that side of the table all week.

Mr Spencer: I think he has answered your question.

The Witness: I think I have answered the question.

Mr. March: I would rather have you answer the question directly if you can, yes or no.

The Witness: I would rather not answer the question that way.

Mr. March: That's all I want you to say.

Mr. Spencer: You are perfectly willing to answer it the way you have answered it?

The Witness: Yes.

By Mr. March:

Q. Mr. Dickinson, has your company made any estimate of the reserves of the Panhandle field of Texas?

A. Yes, Mr. Peterson has made an estimate of that.

Q. Anyone else for your company?

Mr. Spencer: Now, Mr. Examiner, I am willing to let him go, but we'll get involved in something that—

Mr. March: I am not going to get involved. I have just got two or three questions.

The Trial Examiner: Try and cut this short.

Mr. Spencer: What difference does it make?

Mr. March: It makes a great deal of difference.

The Trial Examiner: Mr. March, did you ever make an estimate—Mr. Dickinson?

The Witness: No.

Mr. March: Is that as short as you want it, Mr. Examiner?

The Trial Examiner: That's as short as I want it.

Mr. March: It is not as short as I want it, but if the Examiner rules I won't—

The Witness: I have never made an estimate of reserves, if that's what you meant.

The Trial Examiner: That's what I meant.

By Mr. March:

Q. Has your company made an estimate of the reserves outside of the estimate of reserves made by Mr. Peterson?

Mr. Spencer: The company doesn't make an estimate of reserves.

By Mr. March:

Q. Have you employed anyone else to make an estimate of reserves for you?

A. Yes, we have.

Q. Who were those?

A. J. D. Thompson, Jr. and Mr. C. Don Hughes.

Q. The same individuals that have been here in this hearing room all week?

A. Well, I don't remember whether they have been here—

Mr. Spencer: They really haven't been here all the time.

The Witness: I don't think some of them have.

By Mr. March:

Q. What is Mr. Peterson's connection with your company?

A. Chief geologist for the Texoma Natural Gas Company.

Q. He is employed by your company?

A. Yes.

Drainage in Texas Panhandle Field.

Testimony of C. H. Dunlap, Witness for Canadian.

C. H. Dunlap identified a series of pressure contour maps each titled "Rock Pressure Contour Map, Texas Panhandle Gas Field," which series of maps was marked for identification as Exhibit 239 and was later received in evidence. The witness' testimony concerning these maps is shown in Volume LXXXI, pages 11926 to 11942. The maps show pressure conditions in the Texas Panhandle Field for the years 1933, 1934, 1935, 1936, 1937, 1938, 1939 and 1940. The first map of the series which is dated 1925, shows the general outline of the field, all of which is colored in yellow, and shows the field in its original virgin pressure condition.

The 1933 and 1934 maps are based upon the pressure contour (isobar) maps prepared by C. J. Peterson, which maps were subsequently identified by Peterson, Volume LXXXII, pages 12275 to 12286.

The maps from 1935 to 1940, inclusive, are based upon

the pressure contour (isobar) maps prepared by the Railroad Commission.

The different colors on the maps represent different pressure bands, each color representing a 50-pound pressure band. There are seven colors in all, starting with pressures from zero to 150 pounds and going up to pressures above 400 pounds. The red color, as shown on the 1940 map, represents the area in which the pressures are lower than 150 pounds; the gray color, which is the next higher band, represents pressures from 150 to 200 pounds; the orange color, which is the next higher band, represents pressures from 200 to 250 pounds; the green color, which is the next higher band, represents pressures from 250 to 300 pounds; the blue color, which is the next higher band, represents pressures from 300 to 350 pounds; the brown color, which is the next higher band, represents pressures from 350 to 400 pounds, and the yellow color, which is the highest band, represents pressures above 400 pounds, as based upon the pressure survey made by the Railroad Commission in mid-summer, 1940. These colors represent the same pressure bands on the entire series of maps. It will be noted that the red color does not appear at all on the 1933 map. This is due to the fact that there were no pressures below 150 pounds that year. The red color shows up for the first time in a small area in Gray County on the 1934 map and is shown again in the area around Borger on the 1935 map.

Each map contains other data in the upper righthand corner, being average weighted rock pressures and withdrawals of gas. This portion of the maps was not received in evidence.

Dunlap had been preparing these maps over a period of years and they were not prepared for this particular hearing.

The witness testified on cross-examination that he was a draftsman and that the maps were as exact a duplication of the Railroad Commission's maps as he could make them.

C. H. DUNLAP further testified on cross examination (Vol. 81, pp. 11926-11936) as follows:

C. H. DUNLAP,* called as a witness by and on behalf of the respondents, being first duly sworn, was examined and testified as follows:

Direct Examination.

By Mr. Keffer:

Q. Your name is C. H. Dunlap?
A. Yes, sir.
Q. You live in Amarillo, Texas, Mr. Dunlap?
A. Yes, sir.
Q. I hand you a series of maps, Mr. Dunlap, and I will ask you if those maps have been prepared by you and under your direction.
A. Yes, sir.

Mr. Keffer: I will ask, Mr. Examiner, that the series of maps be given an exhibit number for identification.

The Trial Examiner: Very well, Mr. Keffer. Is there any particular title for that map?

Mr. Keffer: It is a series of maps entitled "Rock Pressure Contour Map, Texas Panhandle Gas Field."

The Trial Examiner: It will be marked for identification as Exhibit No. 239.

(Exhibit 239, Witness Dunlap, marked for identification.)

By Mr. Keffer:

Q. Mr. Dunlap, referring to the rock pressure contour map of the Panhandle field which has been marked as Exhibit No. 239, I will ask you if that series of maps represents the Texas Panhandle gas field?
A. Well, so far as I know, yes.
Q. All right. Now, the first map at the top colored all in yellow, that is the outline of the Texas Panhandle gas field as it was before any depletion occurred?
A. Yes.
Q. And beginning with 1933 and covering 1934, 1935, 1936, 1937, 1938, 1939 and 1940, you have shown the same

outline of the field and have also shown pressure contours for those years, have you not?

A. Yes, sir.

Q. Take the map for 1933 and 1934. What is that based upon as far as the pressure contours are concerned?

A. Well, those maps were made by me when I worked for the Texoma Natural Gas Company under Mr. C. J. Peterson.

Q. The maps beginning with 1935 through to 1940, inclusive, with respect to pressure contours shown upon those, what is that based upon?

A. Copies of the Railroad Commission's maps.

Q. And are representative of the Railroad Commission's maps which show the pressure contour bands in the Texas Panhandle gas field?

A. Yes, sir.

Q. And shows the field as outlined by the Railroad Commission for those years?

A. Yes, sir.

Q. Now, those pressure bands represent 50 pounds differentials in pressure, do they not?

A. Yes, sir.

Q. You have how many colors? You might take the 1940 map as being illustrative.

A. One, two, three, four, five, six, seven.

Q. It starts with pressures below 150 and runs to pressures above 490, is that not correct?

A. That is correct.

Q. The red color represents pressures below 150 pounds, does it not?

A. Yes, sir.

Q. What would you call the next—a slate color?

A. A gray color.

Q. That represents pressures between 150 and 200 pounds?

A. Yes.

Q. What is the next color?

A. Orange.

Q. Orange represents pressures from 200 to 250 pounds?

A. That is right.

Q. The green represents 250 to 300 pounds?

A. Yes.

Q. And the blue represents pressures from 300 to 350 pounds?

A. That is right.

Q. And the brown from 350 pounds to 400 pounds?

A. That is right.

Q. And the yellow represents pressures above 400 pounds.

A. That is right.

Q. Now, what experience have you had in draftsmanship, Mr. Dunlap?

A. Well about fourteen years?

Q. Did you give a considerable part of your time to work of this character?

A. Practically all of it.

Q. Now, there is also shown on the map certain weighted average rock pressures. Was that taken from the Railroad Commission's records?

A. I think it was. I didn't get these figures myself but I think they are Commission's figures.

Q. All right. It also shows total withdrawal figures on a 14.65 base. Those figures as I understand it were furnished by Mr. McCue of the Columbian Carbon Company?

A. That is right.

Mr. March: Now, I object to leading the witness too much.

Mr. Keffer: It is such a simple matter, Mr. Examiner—

The Trial Examiner: It is not at all harmful, Mr. March.

Mr. Keffer: I am going to make just a statement in this connection with respect to those pressures and with respect to the withdrawal figures which were furnishind by Mr. McCue. If Commission's counsel have any objection to those going in, we will not offer them. I have no objection to it going in or not going in, it is entirely up to Mr. Lange and Mr. March.

Mr. March: I want to see the working papers immediately on these maps.

Mr. Keffer: What do you mean?

Mr. March: I don't want to waste three or four days, I want to see them right now.

Mr. Keffer: Why, the working papers are simply the maps of the Commission, Mr. March, which you have in the Commission reports, and just about the same scale that this is. Will not that suffice? There isn't any working papers except that this is a reproduction of the map. That's all there is to it.

Mr. March: I'll ask the witness a couple of questions.

By Mr. Keffer:

Q. You have been making these maps over a number of years, have you not, Mr. Dunlap?

A. Yes.

Q. And they have not been prepared for this case?

A. No.

Mr. Keffer: All right, Mr. March, that's all.

Cross Examination.

By Mr. March:

Q. You are just a draftsman?

A. That's right.

Q. And all you know is what somebody told you to put on these sheets?

A. That's right. I just copied the Commission maps.

Q. These are identical with the Commission maps?

A. As far as I could say, yes, sir. You see the Commission map is a large scale map. This has been reduced to approximately ten miles per square inch and as far as I could say, they are correct.

Q. There is a great deal of inaccuracy in here, isn't there, if you reduced them that much?

A. Well, it depends upon what you call inaccuracy. If you were to scale it off you might find a few pounds difference.

Q. Under whose direction did you prepare these maps?

A. These maps were prepared more or less just as a picture. They weren't prepared for this case.

Q. Under whose direction?

A. Under my direction.

Q. Under your direction?

A. Yes.

Q. Who gave you orders to prepare the map?

A. I made those for the Panhandle Eastern.

Q. Under whose supervision?

A. Mine.

Q. Do I understand this isn't more nor less than a copy of the Railroad Commission maps?

A. Yes.

Q. Up to what year?

A. 1940.

Q. How far did you go—you mean the 1933 map is a Commission map?

A. The 1933 and 1934 maps were Texoma's.

Q. Who gave you those?

A. Mr. Peterson. I worked for him at the time.

Q. You prepared these two under the direction of Mr. Peterson, this 1933 and 1934 map?

A. Yes, sir. Now, let me ask a question. Are you asking about this map or the originals?

Q. I am trying to find out under whose direction you prepared these maps—all of them.

A. These, I say, I prepared for Mr. Field. It was his idea. I did all the work. In other words, he is just a representative of the Panhandle Eastern in Amarillo and he wanted a map made and everything was my work.

Q. By whom are you employed now?

A. Hagy, Harrington & March.

Q. Now, let's see, is there any other data on here that was not taken from the Railroad Commission maps correctly?

A. Well, now, as I say—you mean on the contours, the map itself, or the figures.

Q. I mean any data on the face of these maps. You enumerate it and designate what has not been taken from the Commission maps.

A. Well, the maps from 1935 on were from the Commission direct. The figures, as Mr. Keffer told you, were from H. W. McCue. I think that he got them from the Commission, but I won't—

Mr. March: Mr. Keffer, I think we can talk about this off the record and see what working papers there are, and we would object to anything going in here that you don't have a witness to support.

Mr. Keffer: That's all right. Mr. Lange and Mr. March you have all of the Railroad Commission reports since 1935, and Mr. Examiner, those reports do show maps on the same pressure contour bands and they can very readily be checked.

Mr. March: I have some of them but they are in Washington, but I want to see your working papers on this.

Mr. Keffer: You seem to have a different conception of what a working paper is at times than what I have.

Mr. March: Those new maps aren't Railroad Commission maps.

Mr. Keffer: They were worked out by Mr. Dunlap.

Mr. March: All right, I want to see the basic data Mr. Peterson had in constructing those maps. I don't want to see it today but I don't want to wait two or three days.

Mr. Keffer: I don't know that they are here, Mr. March. If this witness says that these are a reproduction of those Commission maps, I fail to see how having the original maps here would add anything to it. The witness is under oath and he has stated that he has accurately reproduced them.

Mr. March: Yes, but I don't even know where Mr. Peterson got the maps.

Mr. Keffer: He made them up from the pressures existing in the field at that time. The basic data, of course, are pressures existing at those periods.

Mr. March: I am requesting those working papers.

The Trial Examiner: I think we might shorten this up, Mr. Keffer. Do you wish to offer the exhibit?

Mr. Keffer: Yes.

Mr. March: I object to it without having had an opportunity to look at the working papers.

The Trial Examiner: You have cross examined him, Mr. March.

Mr. March: I haven't cross examined him, Mr. Examiner.

Here are two maps in here. He is just a draftsman. I

don't know where Mr. Peterson got the data on the 1933 and 1934 maps. They aren't Railroad Commission maps.

The Trial Examiner: So far as I am concerned, he has laid a proper foundation for the map. You may state your objection.

Mr. March: I want to cross examine the witness. If you are going to let these things go in without cross examination, we object to that.

The Trial Examiner: You have been afforded an opportunity to cross examine the witness on these maps.

Mr. March: Well, I'll cross examine him right now on them.

Q. I will show you the map for 1933 and I will ask you, do you know whether that is an accurate reproduction of the pressure contours in 1933?

A. As Mr. Peterson contoured them, yes, sir.

Q. I want to know if you know of your own knowledge.

A. As you said, I am just a draftsman. I am no engineer. I can't say that the pressures are correct or anything else.

Q. In other words, they might be something different as far as you know?

A. As far as I know, the map is correct.

Q. You have no idea what the pressure contours were as of 1933, do you?

A. Just how do you mean?

Q. I mean from an engineering standpoint, you didn't construct the map?

A. No, I did not.

Q. In 1934—I show you the pressure contour map for that year and I will ask you if you constructed it and the data was compiled by you.

A. I did not.

Q. I will ask you, have you any knowledge as to what the pressure contours were as of 1934.

A. I do not.

Q. You just took the information Mr. Peterson gave you?

A. That's right.

Testimony of J. B. Massa, Witness for Canadian.

Qualifications

He is thirty-nine years of age; resides at Pampa, Texas. He is a registered petroleum engineer "Natural Gas" State of Texas, and is now engaged in a consulting practice.

He has been engaged in the oil and gas business since 1920. His business experience has been as follows: (Vol. LXXXVI, pp. 13049-13051, Exhibit 256, p. 1.)

> Tide-Mex Oil Company, Zacamixtle, Vera Cruz, Mexico, 1920-1922. Engineering Department, doing surveying and construction work and oil production and transportation.
>
> Wooten Hughes Company, Ranger, Texas, 1923-1924, Natural Gasoline Plant Construction plant operation, gas measurement and testing and plant efficiency work.
>
> Phillips Petroleum Company, Ranger, Texas; Borger, Texas, and Pampa, Texas, 1925-1929; plant efficiency work, plant operation, and gas supply supervision.
>
> White Eagle Oil & Refining Company, Pampa, Texas, 1930-1931, field superintendent, Gas Department.
>
> Railroad Commission of Texas, Oil and Gas Division, Pampa, Texas. Assistant Deputy Supervision in charge of Natural Gas Conservation Work in the Texas Panhandle Field.
>
> Consulting Engineer, Pampa, Texas, 1934 to date, during which time the major portion of his work has been in connection with the Texas Panhandle Gas Field.

Increase of Production in Canadian Area and Its Effect Upon Canadian Reserves

Direct testimony of Massa on this subject is contained in Volume LXXXVI, pages 13051 to 13086, Exhibit 256, pages 2 to 12.

Massa submitted on direct examination Exhibit 256, which exhibit consists of his study of the rate of production of natural gas from the Area therein referred to as the "Canadian River Gas Company Area," the increase in the rate of gas production from the area referred to, and the cause

of such increase in the rate of production, and an estimate as to the future rate of production from the Area, all of which matters have a bearing upon drainage from the leases and reserves owned by Canadian. The Area which Massa studied particularly is described by metes and bounds on pages 2 and 3 of Exhibit 256, and generally includes all of the proven gas field located in Hartley, Moore and Potter Counties, Texas, and that portion of the field located north of the Canadian River in Hutchinson County, Texas, and a small portion of the southwestern portion of Hutchinson County, Texas, and the northeast part of Carson County, Texas; and which is hereinafter referred to as the Canadian Area.

There is attached to Exhibit 256 and made a part thereof the following:

Exhibit A is a table showing the annual rate of gas production from the Canadian Area.

Exhibit A-1 contains curves showing (a) the annual rate of gas production by Canadian, and (b) the total annual rate of gas production from the Canadian Area.

Exhibit A-2 is a curve showing the annual rate of production of sweet gas by companies other than Canadian from the Canadian Area.

Exhibit A-3 is a curve showing the annual rate of production of sour and casinghead gas by companies other than Canadian from the Canadian Area.

Exhibit "B" is a table showing the cumulative production from the Canadian Area.

Exhibit B-1 contains curves showing (a) the cumulative production of Canadian and (b) the total cumulative production from the Canadian Area.

Exhibit "C" is a table showing the estimated future annual rate of production from the Canadian Area.

Exhibit "D" is a table showing the estimated future cumulative production from the Canadian Area.

All of the above described instruments constitute a part of Exhibit 256 and are found at the end of that exhibit.

Past Production from Canadian Area

Exhibits A and A-1 show that there has been an annual increase in the volume of production from the Canadian Area since 1929, the rate of increase varying from four billion to sixty-seven billion cubic feet per year. The rate of production from the Area during 1929 was twenty billion cubic feet per year compared to an indicated production from the Area for 1939 of three hundred billion cubic feet per year, an increase of two hundred eighty billion cubic feet. Stated another way there were almost fifteen times as much gas produced from the Area in 1939 as in 1929.

Exhibits A and A-1 show also that prior to the year of 1932 the production of Canadian exceeded the production of all others producing gas from the Area. However, in 1932 the combined sweet, sour and casinghead gas production of others exceeded that of Canadian for the first time, and by 1934 the production of sweet gas alone by others was in excess of the production of Canadian for the first time. Production from the Area by Canadian for the year 1939 will be approximately forty-one billion cubic feet. This amount represents 32% of the total sweet gas or 13.6% of the total sweet, sour and casinghead gas produced from the Area for the year.

Exhibits B and B-1 show that by the year of 1934 the cumulative production of other companies was equal to that of Canadian, and that by the year of 1936 the cumulative production of other companies was more than double the production of Canadian.

There has been an increase in the annual rate of production of gas from the Canadian Area in amounts shown by Exhibit A-1, and that the increase in the rate of production of gas from the Area is due primarily to the increased rate of production of companies other than Canadian.

Estimated Future Production from
Canadian Area

The trend of the annual rate of production curve, Exhibit A-1, shows that an increase in the annual rate of production of gas in the Canadian Area may be expected in future years.

Any increase in the annual rate of gas production in the Area will be the result of a shift of current production from

other parts of the field to the Area, or increased market outlets.

From a study of existing conditions in the sweet gas producing zone of the field it is apparent that there will be some shift of production from the balance of the field to the Canadian Area in future years; however, no definite statement as to the amount of shift that will take place nor the time when such shift will occur can be made.

In the past, a large part of the shift of production of sweet gas that has occurred has been caused by lease consolidations on the part of Texoma Natural Gas Company. These consolidations have allocated more production to Texoma leases located in the Canadian Area due to the fact that Texoma owns large tracts of undrilled acreage in this Area but as a result of the lease consolidations this undrilled acreage is given consideration in the Company's allocation of production between its several leases, the allocation of production being based on total lease acreage multiplied by average lease open flow.

The consolidation of leases has been practically completed and most all of Texoma's acreage holdings are now considered in allocation of production. For this reason, only a small shift of production of sweet gas to the Canadian Area may be expected as a result of Texoma's consolidations of present acreage.

The operations of sweet gas pipe line companies, other than Canadian and West Texas Gas Company, now taking gas from the Canadian Area will result in a shift of sweet gas production to the Area for reasons that will be enumerated below.

One reason to expect a shift of production of sweet gas to the Canadian Area is a block of acreage, owned by Shamrock Oil and Gas Corporation, of approximately twenty thousand acres. At the present time this acreage has no market outlet but is bearing annual delay rentals. Naturally this company is and will continue to endeavor to secure a market for the gas that could be produced from this acreage.

Should the Shamrock acreage be sold to or given a market outlet by a gas pipe line company, there would be a shift in the production of sweet gas to the Canadian Area.

Since Northern Natural Gas Company's present supply of gas is located in Carson and Gray counties, where earlier abandonment of wells may be expected to occur, it is not unlikely that this company would be interested in the Shamrock acreage.

Texoma Natural Gas Company and Cities Service Gas Company are now producing large volumes of sweet gas from the field lying east of the Canadian Area and particularly in eastern Carson County and in Gray County. These areas already have a much lower gas pressure than the areas further west. It is reasonable to assume that such areas will be depleted earlier than the Canadian Area. It is apparent, therefore, that as pressures decline and less gas is available in such areas that both Texoma Natural Gas Company and Cities Service Gas Company will be forced to take an increasingly larger proportion of their total production from time to time from the Canadian Area and from lands adjacent thereto. Texoma Natural Gas Company has been increasing its withdrawals from the Canadian Area in recent years and is now taking more than half of its total production from this Area. Cities Service Gas Company has also been increasing its production from this Area during the past few years, and as above stated, will be forced to produce increasingly larger volumes from this Area and lands adjacent thereto as less and less gas becomes available in eastern Carson and Gray Counties.

The greater portion of the Panhandle Eastern reserves are already in the Canadian Area, but as pressures become lower in its wells outside of the Area and in the wells of Huber Petroleum Company, from whom it purchases gas, it will also be forced to take a larger proportion of its gas from the Canadian Area.

In addition to the gas pipe line companies now taking gas from the Canadian Area, there are other gas pipe line companies taking gas from that part of the field lying east of the Canadian Area, including a substantial quantity of gas sold by the Phillips Petroleum Company to the Northern Natural Gas Company, all of which is produced in Gray and Wheeler Counties where pressures are already very low. It is reasonable to expect a shifting of this gas production to the West, particularly the production of the Phillips Petroleum Company as this company has available

large quantities of sweet gas in or near the Canadian Area. It also is the largest owner of sour gas lands in Moore and Hutchinson Counties.

Exhibit A-3 shows that in the past there has been a rapid increase in production of sour gas in the Canadian Area. due partially to increased markets and partially to the rapid development of that part of the sour gas zone, thus causing a shift of sour gas production to the Area.

There will continue to be a shift of current production of sour gas to the Canadian Area due to the fact that sour gas production in the Texas Panhandle Field is regulated by a State proration order under which well allowables are determined on the basis of 1/3 on relative potentials and 2/3 on a relative acre/pound factor. The acre/pound factor is obtained by multiplying the lease acres by the well rock pressure.

The State proration order will bring about a shift of current production of sour gas to the Canadian Area due to the fact that there are approximately two-hundred-twenty-five undrilled, six hundred forty acre sour gas locations in the Area compared to about four such locations outside the Area. The weighted average pressure of the sour acreage in the Canadian Area is 357 pounds compared to 197 pounds for the sour acreage outside of the Area at August 1, 1939. The average open flow or potential of the sour wells in the Canadian Area is in excess of twenty-four million cubic feet per well per day compared to an average open flow or potential of nine million cubic feet per well per day for sour wells located outside the Area.

During the year of 1938 there were thirty-five sour gas wells drilled in the Canadian Area compared to eleven drilled outside the Area and during the year 1939 there were twenty-two sour wells drilled in the Area compared to five drilled outside the Area.

Practically all of the sour gas acreage in the field is under lease contracts, and in view of the past development it appears that a steady development of the present undrilled acreage may be anticipated.

As development takes place, it naturally follows that there will be a shift in current production of sour gas to the Canadian Area, for all of the undeveloped acreage lies

therein and the average well potential and average pressure of the Area are much higher than similar factors for the remainder of the sour zone. The effect of the proration formula is to give large allowables to areas of high potentials and large acre-pound factors and production occurs in relation to allowables.

The table appearing at the end of this paragraph illustrates the shift in production of sour gas from the balance of the field to the Canadian Area expected as a result of the complete development of the sour gas zone over a seven-year period. The table is based upon the application of the State proration order with a daily market outlet for 690,000,000 cubic feet of gas per day, 14.65 pound base.

It has been assumed that there will be an average of thirty-two wells drilled per year for seven years, and that pressure in the sour zone of the Canadian Area will decline at the rate of one pound per acre per 9,600,000,000 cubic feet of gas produced while the sour zone of the balance of the field declines at the rate of one pound per acre per 16,700,000,000 cubic feet of gas produced, these decline rates representing the average relation of pressure loss and production for the two year period July 1937 to July 1939, based on Railroad Commission figures. In addition, consideration was given to the fact that there are a number of sour wells lying outside the Canadian Area, having an annual production of approximately fifteen billion cubic feet per year, which are exempt from the proration order, and that the allowable gas allocated to the sour gas zone of the Canadian Area is approximately fifteen billion cubic feet per year in excess of production. Present rates of production of casinghead gas have been considered as constant:

Table

Annual Production—Sour and Casinghead Gas
1939—16.4 lbs.—174,780,000 Mcf.

	Estimated Production Sour and Casinghead Gas 16.4 lbs. Mcf.
1940	186,726,000
1941	188,657,000
1942	191,356,000
1943	193,380,000
1944	194,955,000
1945	196,081,000
1946	196,755,000
1947	197,205,000
1948	195,405,000
1949	193,605,000
1950	191,131,000
1951	188,431,000
1952	185,457,000
Total	2,499,144,000

There now exists a pressure differential of 24 pounds per acre between the sweet and sour zones of the Canadian Area. The sour zone comprises only 39% of the total acreage of the Area yet the sour production represents approximately 59% of the total production from the Area. Obviously the differential in pressure between the two zones will increase and large quantities of sweet gas will migrate to the sour zone.

Increased market outlets for the sweet gas zone is a subject on which Massa has not made a thorough study. However, a study has been made of this subject by Hendee (Exhibit 255) upon which Massa's figures as to future production from the sweet gas area are based.

In the sour zone, it is Massa's opinion that there will be an increase in the market outlet for sour gas by virtue of a decline in the production of casinghead gas, but that there will not be any material change in the combined total production of the two types of gas.

Exhibit "C" of Exhibit 256 shows his estimate of the

future annual rate of production of gas from the Canadian Area, based upon Hendee's estimate of sweet gas production for the field and Massa's estimate of the shift in production for sour gas. Exhibit "D" of Exhibit 256 shows cumulative production based on Exhibit "C."

Although he has recorded several instances where shifts in sweet gas production may reasonably be expected, the figures of future sweet gas production by companies other than Canadian from the Canadian Area are based upon current proportions of production as between the Canadian Area and other parts of the field, and do not reflect the shift of production that will undoubtedly occur. It must also be borne in mind that there are now three gas pipe lines serving Wheeler County, in addition to the Phillips Petroleum Company line, and as Wheeler County becomes more and more depleted these lines must necessarily be extended westward if the companies owning the same continue to take gas from the Texas Panhandle Field.

The witness further testified that Table A (Exhibit A) of Exhibit 256, shows that for 1928 and prior, the Canadian has produced slightly in excess of thirty billion cubic feet of gas from the Area being studied and that the total production of all companies through 1928 and prior, was only thirty-one and a half billion feet of gas and that Canadian therefore has produced practically all of the gas from the Area through the year 1928. That since 1928 the other companies operating in the Area produced an increasingly larger volume of gas as compared to the Canadian's production and that the increase has been out of all proportion to Canadian's increase. The production for the most part adjacent to the Canadian acreage has been sweet gas production. Exhibit 179 of the Commission's witness Hammer shows the sour gas line to be generally north and northeast of the Canadian acreage.

From the beginning of the life of the field to the end of 1933 Canadian produced more sweet gas every year than all of the other companies combined but during the year 1934 all of the other companies for the first time produced more sweet gas than Canadian produced.

Exhibit B (Table B) of Exhibit 256 shows cumulative production of all types of gas produced by Canadian and

also produced by Canadian and also produced by all other companies. The witness stated that a reference to this chart shows that in the year 1938 the cumulative production of sweet gas by all other companies producing in the Area being studied was in excess of the cumulative production of Canadian. The annual rate of production of all other companies, as shown by Exhibit A of Exhibit 256, became greater than the annual rate of production of Canadian for the first time in 1934, but Canadian had accumulated a back log of heavier production than all other companies during the preceding years and it took until sometime within the year 1938 for the total production of all other companies to equal the total production for all time of Canadian in so far as sweet gas production is concerned.

In 1938 the witness stated that the production of Canadian, as shown on Exhibit A of Exhibit 256, was 38,950,311 Mcf. and that the sweet gas production of all other companies for that same year was 73,995,612 Mcf., and in 1939 the rate of production of all other companies was more than twice that of Canadian, as shown by the same table.

Again referring to Exhibit B of Exhibit 256 the total cumulative production of sweet gas by Canadian at the end of 1937 was slightly in excess of 260 billion cubic feet, and the total cumulative production of sweet gas by all other companies producing in the Area was a little less than 243.5 billion cubic feet.

Starting with the year 1938 with a slight difference in favor of Canadian it was probably mid-year in 1938 before the cumulative production of sweet gas of all companies equaled the cumulative production of sweet gas by Canadian from the Area in question.

Referring again to Exhibit B (Table B) Exhibit 256, it is shown that in 1933 the total cumulative production of all companies, including Canadian and including production of all types of gas, was in excess of 209 billion cubic feet at the end of the year 1933 and the cumulative production of Canadian alone at the end of 1933 was in excess of 122 billion cubic feet. At the end of 1933, therefore, Canadian had produced more gas than all other gas production of

all types by all other companies in that area and it was during the year 1934 for the first time that all other gas companies, including all types of gas production, exceeded the production of Canadian.

The witness then referred to Exhibit A-1 (Chart A-1 of Exhibit 256) which chart contains a graph showing the annual rate of production of Canadian. It also contains a graph or curve showing the total annual rate or production of gas from the entire Area. This chart and the curves thereon show that since the end of the year 1933 particularly, the total annual rate of production has been increasing with respect to the annual rate of production of Canadian. The curve of Canadian is represented by a fairly straight line while the curve representing the total annual rate of production is represented by a sharply ascending line beginning at the end of the year 1933.

Accelerated Pressure Decline of Canadian Reserves And of Reserves Generally in Canadian Area

Massa also testified with respect to Exhibit 257 (Vol. LXXXVI, pp. 13067-13086, Exhibit 257, pp. 1-3) that this exhibit was prepared for the purpose of showing that in future years it is reasonable to expect that the volume of gas produced per pound loss of pressure will be smaller than the past and present rates of production per pound loss of pressure.

He stated that in considering this matter it must be borne in mind that much of the undeveloped high pressure acreage lies along the edges of the field. Past experience in the field has proved that most of the edge acreage will produce much smaller volumes of gas per pound loss of pressure than the average volume per pound for the field.

Another fact that must be borne in mind is the location of the leases of Canadian, both with respect to the edges of the field and with respect to pressure conditions in the field. These leases extend along the entire southern boundary of the field in Potter County and the southern and western boundaries of Hartley County. The leases of the Canadian for the most part lie in the highest pressure area of the field.

The graph (shown in Exhibit 257) of gas production per acre, in Mcf. 16.4 pound base, per pound loss of pressure, plotted in relation to cumulative production in billions of cubic feet, 16.4 pound base, shows clearly what is occurring in the western end of the Texas Panhandle Field in regard to declining gas production per acre per pound loss of pressure (that is, production per acre pound according to Hammer's figures).

The graph is based on data compiled from basic data used by Hammer, Commission Engineer, in making his estimate of gas reserves.

Curve "A" is based upon production and pressure data including all of Hartley, Moore and Potter Counties, Quadrant 4 of Carson County and Quadrants 3, 4 and 5 of Hutchinson County.

Data Used

	Acre Pounds	Acre Pound Loss	Production 16.4 lbs. Mcf.	Production Mcf. Acre Pound Loss	Cumulative Production
1935	320,492,239				
1936	317,641,213	2,851,026	210,940,635	73.99	210,940,635
1937	313,160,082	4,481,131	254,569,005	56.81	465,509,640
1938	306,397,165	6,762,917	289,318,127	42.78	754,827,767
1939	297,686,827	8,710,337	301,482,036	34.61	1,056,309,803

Curve "B" is based upon production and pressure data of those quadrants wherein lie the leases of the Canadian, including all of Hartley and Potter Counties, Quadrants 1, 2 and 3 of Moore County, Quadrant 4 of Carson County and Quadrant 3 of Hutchinson County.

Data Used

	Acre Pounds	Acre Pound Loss	Production 16.4 lbs. Mcf.	Production Mcf. Acre Pound Loss	Cumulative Production
1935	177,400,264				
1936	175,639,615	1,800,649	109,546,235	60.84	109,546,235
1937	173,671,356	1,968,259	117,805,591	59.85	227,369,826
1938	171,192,700	2,478,586	124,461,586	50.21	351,831,412
1939	167,605,974	3,586,796	133,135,223	37.12	484,966,635

The graph shows plainly that the volume of gas produced per acre pound loss of pressure has been declining

rapidly and the trends of the curves are such as to indicate that this decline will continue.

Declines in production of natural gas per acre pound loss of pressure in the Texas Panhandle Field can be attributed to but two causes, drainage and variations in the acre content of gas in various parts of the field.

Due to the fact that Curve "B," representing the area of the Canadian leases, is declining at a greater rate than is Curve "A," representing the western end of the field, it is reasonable to conclude that the leases of Canadian will produce a smaller volume of gas per acre pound loss of pressure than the average for the western zone and to conclude from both of the curves and the other enumerated facts that the rate of production per acre pound loss of pressure will continue to decline.

Massa referred to Exhibit 257 and explained the curves shown graphically in that exhibit. He stated the curves were constructed from data taken from witness Hammer's Exhibit 180 and the quadrants described in Exhibit 257 are the quadrants shown on Hammer's Exhibit 179. The quadrants, as shown on Hammer's Exhibit 179, correspond almost exactly with the Canadian Area which Massa defined and discussed in Exhibit 256, the only difference being that Massa had not included all of quadrant 3 in Hutchinson County in defining the Area which he described in Exhibit 256 as the Canadian Area. He had, however, included about half of Quadrant 3, Hutchinson County. The graph shown in Exhibit 257, however, includes all of Quadrant 3, Hutchinson County. It was necessary for him to do this because he was using Hammer's calculations and figures and he had no way to break it down into two parts in so far as Quadrant 3, Hutchinson County, was concerned.

The table on page 2 of Exhibit 257 shows that from mid-year, 1935, to mid-year, 1936, the cubic feet of gas per acre produced for each acre-pound loss in pressure was 73.99 thousand cubic feet, and from 1936 to 1937 the production per acre-pound loss had dropped to 56.81 thousand cubic feet and from 1937 to 1938 the production had dropped to 42.7 thousand cubic feet per acre-pound loss in pressure

and from 1938 to 1939 the production had still further dropped to 34.61 thousand cubic feet per acre-pound loss in pressure. There was less than half as much gas produced in the period mid-year, 1938, to mid-year, 1939, as there was produced from mid-year, 1935, to mid-year, 1936, with respect to the acre-pound loss in pressure. (It will be observed from an inspection of Hammer's Exhibit 180 that his production and pressure figures covered annual periods of mid-year one year to mid-year of the next.) The decline in pressure, as related to production, shows that the loss in pressure is greatly accelerated from year to year. If the production per acre-pound loss in pressure had been the same from year to year Curve A as shown on the graph in Exhibit 257, would have been a horizontal straight line.

Curve B, shown on the graph contained in Exhibit 257, represents comparative data plotted from Hammer's data, but pertaining only to quadrants which contain acreage of the Canadian and is the same data utilized by Hammer in making his estimate of Canadian reserves. This curve also shows a decline in acre-pounds from year to year with respect to production, or when correlated with production. The decline is not as rapid at the beginning of the period as it is for the Area as a whole and shown on Curve A but in the last two years particularly, the decline has been greatly accelerated. The four points shown on each curve represent mid-year 1936, midyear 1937, mid-year 1938, and mid-year 1939. If pressures were not dropping more rapidly than production, when related to production, Curve B would be a horizontal straight line; that is, if the production per pound loss in pressure was constant the curve would be represented by a horizontal straight line instead of a line that points sharply downward.

Cross Examination

The testimony on cross examination as to both exhibits (256 and 257) is abstracted together. The cross examination directed to each exhibit covers related subjects and the testimony is presented more clearly by considering them together.

Massa testified on cross-examination with respect to Exhibit 256 that the shift of production in the sour gas

area of northern Moore County, as shown on page 10, Exhibit 256, is based upon the application of the State proration order which he has assumed will remain in effect through 1952. (Vol. LXXXVIII, p. 13268.) In selecting the Area which he has described by metes and bounds in Exhibit 256 he took into account the acreage of Canadian and the surrounding area which contained high pressure acreage. This was done in order to study the future development and shift of production and determine the effect that it would have with respect to increased drainage. He did not include all of Quadrant 3, Hutchinson County, as delineated by Hammer in Exhibit 179, because at the time he made his study he had not seen Hammer's Exhibit and had never heard of Hammer's Quadrant 3, Hutchinson County. (Vol. LXXXVIII, pp. 13369-13370.) He was limiting his study primarily to the high pressure areas in the western part of the Texas Panhandle Field (Vol. LXXXVIII, p. 13373) for the purpose of studying the pressures and the trends of withdrawals. (Vol. LXXXVIII, p. 13374.)

It is the witness' opinion that low pressure areas will be created in northern Moore County and in northern Hutchinson County because of the tremendous withdrawals from those areas and that a situation will be created similar to the low pressure area around Borger and Sanford area. He has studied the production records in the Borger-Sanford area since 1928 and knows that that area has produced many, many, many times over the amount of gas that could possibly have been in place under the acreage in that area. (Vol. LXXXVIII, p. 13382.)

The witness studied the Canadian well pressures as they affected the weighted pressures of the Area. It is the witness' opinion that the wells in northern Moore and northern Hutchinson Counties will create an even greater difference in press-es than exists today and that the gas from the intermediate areas between Canadian leases and northern Moore and northern Hutchinson Counties will migrate northward into that area and that in turn gas from the Canadian leases will be drained to the intermediate areas. In like manner gas is being drained from Canadian acreage into Borger and Sanford area. The migration of gas is a progressive proposition. If a well is drilled and

starts producing that well at first will drain from a comparatively small area but as the pressure is reduced at the well bore and a greater pressure differential is established between that and the higher pressures in the reservoir, drainage starts and the well gradually increases its drainage area. That is what has occurred in the Borger-Sanford area. As the pressure has been pulled down and down and down the effect of the drainage into this area has been extended and is now showing up at remote parts of the field. Regardless of who produces the gas and regardless of where it is produced, when low pressure areas are created there will be a migration of gas to those low pressure areas. The witness further stated that the lower pressure differential existing in central Moore County was not caused entirely by withdrawals within that particular area. (Vol. LXXXIX, pp. 13388, 13891.)

It is not necessary to remove all of the gas from under a well to cause drainage. All that is necessary is to create a pressure differential and the greater the differential the greater the extent of the drainage. It is not necessary to create a void in order to have gas migrate into an area of lower pressure and as long as there is a pressure differential there is a movement of gas. (Vol. LXXXIX, pp. 13394, 13395.) The effect of the migration of gas into the Sanford area, and also the effect of the heavy withdrawals which are occurring in northern Moore County, northern Hutchinson County and central Moore County, are beginning to be reflected in the declining rate of production per pound loss of pressure from the Canadian leases. (Vol. LXXXIX, p. 13396.)

The witness was then asked to explain why the pressures in the Sanford area didn't remain at 430 pounds, the original pressure, if there was effective migration of gas into that area. The witness explained that it would be impossible for the pressures to remain at 430 pounds and that at the present time gas was migrating into the Borger-Sanford area more rapidly than it was being produced because the pressures were increasing. (Vol. LXXXIX, p. 13397.)

During the stripping days when the production from the

Borger-Sanford area was more rapid than the migration of gas into the area the pressures decreased but when the production was decreased then the ratio of production and migration was changed and more gas migrated into the area than was being produced, and therefore the pressures increased. (Vol. LXXXIX, pp. 13401, 13402.) There are some wells in the Borger-Sanford area that did not start repressuring in 1935 when the production was decreased. The area seems to be expanding as the back log of the migration is spreading out. There are some of the wells in which the pressure has increased only for a year or two. (Vol. LXXXIX, p. 13405.)

There was then marked for identification Exhibit 259, which was a list of the wells in the Borger-Sanford area in which the pressures had increased for the period 1935 to 1940. (Vol. LXXXIX, p. 13407.) The witness stated that effective drainage does not mean necessarily that the wells receiving the drainage will increase in pressure. It all depends on whether the rate of withdrawal from the wells was greater than the rate of migration. No one has ever questioned the fact that there was migration of gas into the Borger-Sanford area. The witness was again asked if it were not true that if there was effective drainage that pressures would be maintained notwithstanding the rate of production and the witness again answered that there couldn't be maintenance of pressure as long as the rate of production was in excess of the rate of migration. (Vol. LXXXIX, pp. 13408, 13409.) The witness has not attempted to evaluate the volume of migration of gas into low pressure areas. He has simply attempted to show the trend of drainage. (Vol. LXXXIX, p. 13411.) Migration of gas into the Sanford area has been reflected in lower pressures in central Moore County but is not entirely responsible for the low pressures in Moore County. (Vol. LXXXIX, pp. 13416, 13417.)

The witness further testified that although in his written statement introduced in his direct examination he had pointed out that there were a number of pipe lines operating in the east field, which lines would possibly be extended into the west part of the field as the east field became exhausted; nevertheless, he did not attempt to evaluate

this fact and did not give that possibility any effect in his study of the western part of the field. It is natural to expect, however, that abandonments will occur in the east field first because of the lower pressures existing there now. He did not consider this fact in his estimate of future production in the west field because it could not be definitely evaluated although he does believe that some of the companies operating in the east field will extend their lines into the west field. (Vol. LXXXIX, pp. 13420-13427.) The witness also stated that although he had mentioned that there was a great deal of undeveloped acreage owned by Shamrock Oil and Gas Company adjacent to Canadian and that this acreage would possibly find a market sooner or later, still he did not attempt to evaluate the extent of the possible production from this acreage and it is not reflected in any way in his computations but it is definitely in the picture so far as the future is concerned. (Vol. LXXXIX, p. 13342.)

Witness was then referred to Exhibit 187 by Thompson with particular reference to the Shamrock undrilled acreage in eastern and southern Moore County, which was shown to have pressures ranging from 300 to 350 pounds, and was asked what happened to the gas that came out of that undrilled acreage and the witness replied that it appeared to him that it probably migrated to the Borger-Sanford area. That it could not have gone to Texoma's acreage because the pressures in the Texoma acreage were higher than the pressures in the Shamrock acreage. (Vol. LXXXIX, pp. 13433-13434.) That Canadian in the early part of 1929 and prior and up to 1930 or 1931 was taking more gas from its area than the other companies but the market outlets acquired since then by other companies have enabled them to overcome the cumulative effect of the early Canadian production and that the increase in production of others has been greater than the increase in the Canadian production. (Vol. LXXXIX, p. 13441.)

The witness stated that the shift of production of sour gas into the Canadian Area is based upon the assumption that the market for sour gas will be constant at 690 million cubic feet of gas per day, which is the present allowable production. He has allowed for no increase in this pro-

duction but has considered that the sour gas acreage in the west part of the field will be developed over a seven-year period and that as additional wells are drilled, and additional potential and pro-ratable acre-pounds come into the picture that these wells will be allocated a certain production under the proration order, which is based largely upon acreage. (Vol. LXIX, 13452, 13453.) This estimate is based upon the conditions as they exist today and it was made from the witness' best judgment of the factors that were present. (Vol. LXIX, p. 13454.) The witness, upon being asked whether the use of sour gas for gasoline and carbon black was wasteful, replied that there are so many things involved that it is a relative proposition and as long as the gas is being utilized it might well be claimed that it is not wasteful. (Vol. LXIX, p. 13458.) The witness stated that he could not state definitely that sour gas would be used for carbon black purposes in the future but that he has assumed that things will go on just as they are today. (Vol. LXIX, p. 13459.)

The witness was questioned at length with respect to the compilation of his figures for sweet gas production, and he stated that these were taken from records in the Railroad Commission's office and that where the pressure base was not given he determined from the various producers in the area the pressure base that had been utilized in reporting their production. That the pipe line companies prior to August, 1935, reported their production on a 16.4 pound basis. (Vol. LXIX, pp. 13464-13471.) He also procured his production figures of gasoline plants from the plants that were operating in the area up to 1932 and subsequent to that from Form 3 reports filed with the Railroad Commission and made necessary corrections as to the pressure base. (Vol. LXIX, pp. 13476-13488.)

With respect to Exhibit 257 the witness testified on cross examination that the curve which he had constructed, and which was a part of Exhibit 257, was a very common curve and it showed the rate of production per acre-pound loss of pressure and that natural laws, Boyle's Law, governs the per pound loss of pressure as related to production. The witness plotted the curve in the manner that he did for the purpose of showing the comparison in

the two areas involved. There is nothing complicated about it. If both areas had been of uniform size and uniform acreage it would not have been necessary to reduce the vertical ordinate to acre-pounds but he could have stopped at simply showing pounds, but in order to make a fair comparison of the two curves it was necessary to relate it to acre-pounds. If the fundamentals of Boyle's Law were applied it would show a uniform drop in pressure as related to production, or approximately so, but where the rate of production per pound loss in pressure is constantly declining, as it is in the west part of the field, there is some unknown factor that is causing the simple application of Boyle's Law to give an erroneous answer. (Vol. LXXXIX, pp. 13505-13512.)

In plotting production or pressure loss against production in order to obtain a straight line (horizontal) you would have a constant rate of production per pound loss. This is production per pound loss brought down to an acre basis for the purpose of comparison of curves A and B which are based on different sized areas and since the Canadian curve is declining at a faster rate than Curve A this shows that the Canadian acreage is being drained by the remainder of the acreage in the area. At least the drainage has had its effect and the witness thinks that the variation in the original per acre content has also had its effect, but since 1937 there has undoubtedly been intensive drainage or a variation of the per acre content. In other words the effect of withdrawals is reaching out in the edge acreage which is likely to be less productive than the other acreage. (Vol. LXXXIX, pp. 13514, 13515.)

The trend of Curve B, Exhibit 257, indicates that the rate of production is declining faster in the quadrants which contain Canadian acreage than it is for the area as a whole, which also includes Canadian quadrants. The fact that Canadian acreage lies generally in the high pressure zones and the fact that there is so much of the Canadian acreage along the edge of the field leads to the conclusion that this acreage would produce at a much smaller rate in the future. (Vol. LXXXIX, p. 13527.) All figures indicate that the rate of production in the Texas Panhandle Field per pound loss in pressure is constantly decreasing.

that is, they show a decreasing rate of production per pound loss of pressure weighted as to area. We are constantly getting less production per pound drop. All of the available data indicates a downward trend but the witness cannot say definitely what this trend will be in the future. (Vol. LXXXIX, pp. 13528-13530.)

The witness stated on redirect examination that the production per acre pound loss was determined from the production figures and weighted pressure figures taken from Hammer's working papers. That he simply used Hammer's figures, and this being true, he necessarily included all of Quadrant 3, Hutchinson County, in Exhibit 257, although he had included only a part of it in his study reflected in Exhibit 256. The fact that he did use all of Quadrant 3, since he was using Hammer's figures, had a tendency to hold his curve up. In other words, if he had left out some of the low pressure wells in Quadrant 3, Hutchinson County, his curves would have declined more sharply, but in any event he had simply followed the foosteps of Hammer in his calculations as reflected by Exhibit 257 and used the same quadrants that Hammer had used in estimating the reserves for the Canadian acreage. (Vol. LXXXIX, pp. 13534-13537.)

The southwestern portion of Hutchinson County is gaining gas from the higher pressure areas to the southwest and is also losing gas by virtue of drainage away from the area to the northeast. The fact that pressures have declined a little, or greatly, in that area does not necessarily mean that it was not losing gas to the northeast toward the Sanford area. The movement of gas into the southwestern portion of Hutchinson County from the higher pressures on the southwest is replenishing some of the loss being suffered to the lower pressure areas to the northeast. Movement of gas cannot be restricted to small areas. Small areas cannot well be considered in arriving at the mass movement of gas that necessarily occurs from a high pressure area to a low pressure area. (Vol. LXXXIX, pp. 13538, 13539.) The wells listed on Exhibit 260 which are gaining in pressure in the Borger-Sanford area, do not constitute the only wells in southwest Hutchinson County that are receiving gas by drainage. There are other wells

that are producing gas with much lower than average pressure drops. There is a gradual increase in pressure drops as you get away from the low pressure areas. A well may be receiving gas by underground migration, even though it shows a reduction in pressure from year to year, where the pressure drop is slight in relation to the volume of gas produced. There is no doubt that a well in a lower pressure area is receiving some gas from the high pressure areas adjacent although it may not be retaining it. (Vol. LXXXIX, pp. 13542, 13543.)

With further reference to the increase in the drilling of wells in the Canadian Area, as described by the witness in Exhibit 256, he stated that in 1938 there were 107 wells drilled in the entire Texas Panhandle Field, both east and west fields, and there were 53 wells drilled in the Canadian Area, or 49.5% of all the wells drilled. In 1938 there were 98 wells drilled in the entire Texas Panhandle Field and 58 of these were drilled in the Canadian area, or 59% of the total number of wells drilled. In 1940 there were 94 wells drilled in the field as a whole, and of these 63 were drilled in the Canadian Area, or 67% of the total number of wells drilled. (Vol. LXXXIX, p. 13547.)

In 1940 there were 39 sour gas wells drilled in the field as a whole and of these 34 were drilled in the Canadian Area. The witness had estimated, as shown by his Exhibit 256, that there would be 32 sour gas wells drilled in the Area in 1940. His estimate was less than the number actually drilled. (Vol. LXXXIX, pp. 13547, 13548.)

The witness had previously testified in his direct examination that in 1939 there were 27 sour gas wells drilled in the field, and of these 22 were drilled in Canadian Area and that in 1938 there were 46 sour gas wells drilled in the entire field and of these 35 had been drilled in the Canadian Area. (Vol. LXXXIX, pp. 13061, 13062.)

The witness further testified on recross examination that the rate of decline of pressure in the Canadian acreage is now going down faster than the pressure of the other acreage in the Canadian Area and the Canadian acreage is so located around the edge of the field that gas loss cannot be replaced by drainage from other higher pressure

areas. The pressure in the Canadian acreage is declining more rapidly at the present time and it is quite likely that as the higher pressure areas decrease the pressure differentials will decrease, and for all intents and purposes the pressures will pretty well balance out. (Vol. LXXXIX, pp. 13553, 13554.)

Exhibit No. [illegible]

EXHIBIT "A"

ANNUAL RATE OF GAS PRODUCTION FROM THE CANADIAN RIVER GAS COMPANY AREA

M.C.F.-16.4#

Year	Canadian River Production	Other Companies Sweet Production	Other Companies Sour Production	Other Companies Casinghead Prod.	Total Production
1928 & Prior	30,062,713	172,392	1,350,737		31,585,842
1929	16,688,962	1,935,533	618,307	2,694,028	21,936,830
1930	18,324,487	5,281,286	723,461	2,694,028	27,033,262
1931	18,566,131	8,313,794	1,766,241	2,694,028	31,340,194
1932	20,037,015	11,905,264	2,839,632	8,982,170	43,764,081
1933	19,258,673	15,678,678	10,364,723	8,778,402	54,080,416
1934	26,022,673	40,903,283	46,475,377	7,503,318	120,904,651
1935	30,525,547	45,701,194	60,991,983	15,865,171	153,083,895
1936	38,938,634	50,623,825	96,083,244	17,150,263	202,795,966
1937	41,636,594	62,888,884	142,656,697	15,588,088	262,770,463
1938	38,950,311	73,995,612	152,172,505	11,491,969	276,610,397
7-31-1939	23,979,010	51,519,703	93,948,136	8,007,037	177,453,886
Est. Total for 1939	41,106,996	88,319,496	161,053,944	13,726,344	304,206,660

Exhibit No. 296

4705
23389

EXHIBIT "B"

CUMULATIVE GAS PRODUCTION FROM THE CANADIAN RIVER GAS COMPANY AREA

M.C.F. 16.4#

Year	Canadian River Production	Other Companies Sweet Production	Other Companies Sour Production	Other Companies Casinghead Prod.	Total Production
1928 & Prior	30,062,713	172,392	1,350,737		31,585,842
1929	46,751,675	2,107,925	1,969,044	2,694,028	53,522,672
1930	65,076,162	7,389,211	2,692,505	5,388,056	80,555,934
1931	83,642,293	15,703,005	4,458,746	8,082,084	111,896,128
1932	103,679,208	27,608,269	7,298,378	17,064,254	155,660,809
1933	122,937,981	43,286,947	17,663,101	25,842,656	209,740,685
1934	148,960,654	84,190,230	64,138,478	33,345,974	330,645,276
1935	179,486,201	129,891,424	125,130,461	49,211,145	483,729,171
1936	218,424,835	180,515,249	221,213,705	66,361,408	686,525,137
1937	260,061,429	243,404,133	363,870,402	81,949,496	949,295,600
1938	299,011,740	317,399,745	516,042,907	93,441,465	1,225,905,997
7-31-1939	322,990,750	368,919,448	609,991,043	101,448,502	1,403,359,882
Est. Total for 1939	340,118,736	405,719,241	677,096,851	107,167,809	1,530,112,656

Exhibit No. 256

EXHIBIT "C"

ESTIMATED FUTURE ANNUAL RATE OF GAS PRODUCTION

FROM CANADIAN RIVER GAS COMPANY AREA in MCF

Year	By Canadian River	By Others Sweet Gas	By Others Sour & Casinghead	Total Production 16.4#
1940	43,021,625	90,978,797	186,700,000	320,700,422
1941	45,418,507	93,008,855	190,544,000	328,971,362
1942	50,120,688	100,962,190	194,183,000	345,265,878
1943	53,011,423	106,442,275	199,181,000	358,634,698
1944	56,533,809	112,427,258	202,753,000	371,714,067
1945	59,087,078	116,448,782	203,924,000	379,459,860
1946	59,087,078	116,448,782	204,625,000	380,160,860
1947	59,087,078	116,448,782	205,093,000	380,628,860
1948	59,087,078	116,448,782	203,221,000	378,756,860
1949	59,087,078	116,448,782	201,349,000	376,884,860
1950	59,087,078	116,448,782	198,776,000	374,311,860
1951	59,087,078	116,448,782	195,968,000	371,503,860
1952	59,087,078	116,448,782	192,875,000	368,410,860

Exhibit No. 256

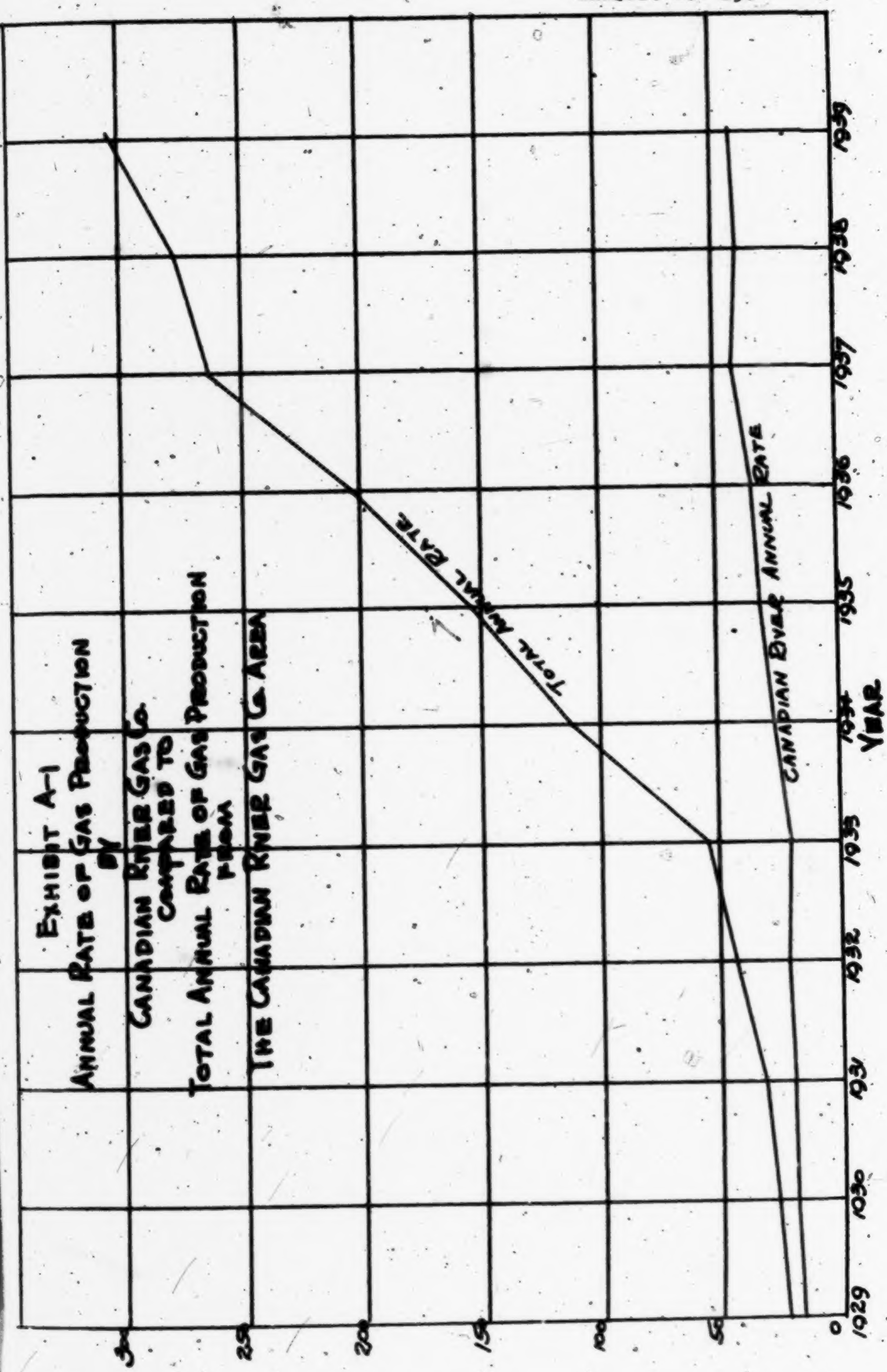


Exhibit No. 256 4711

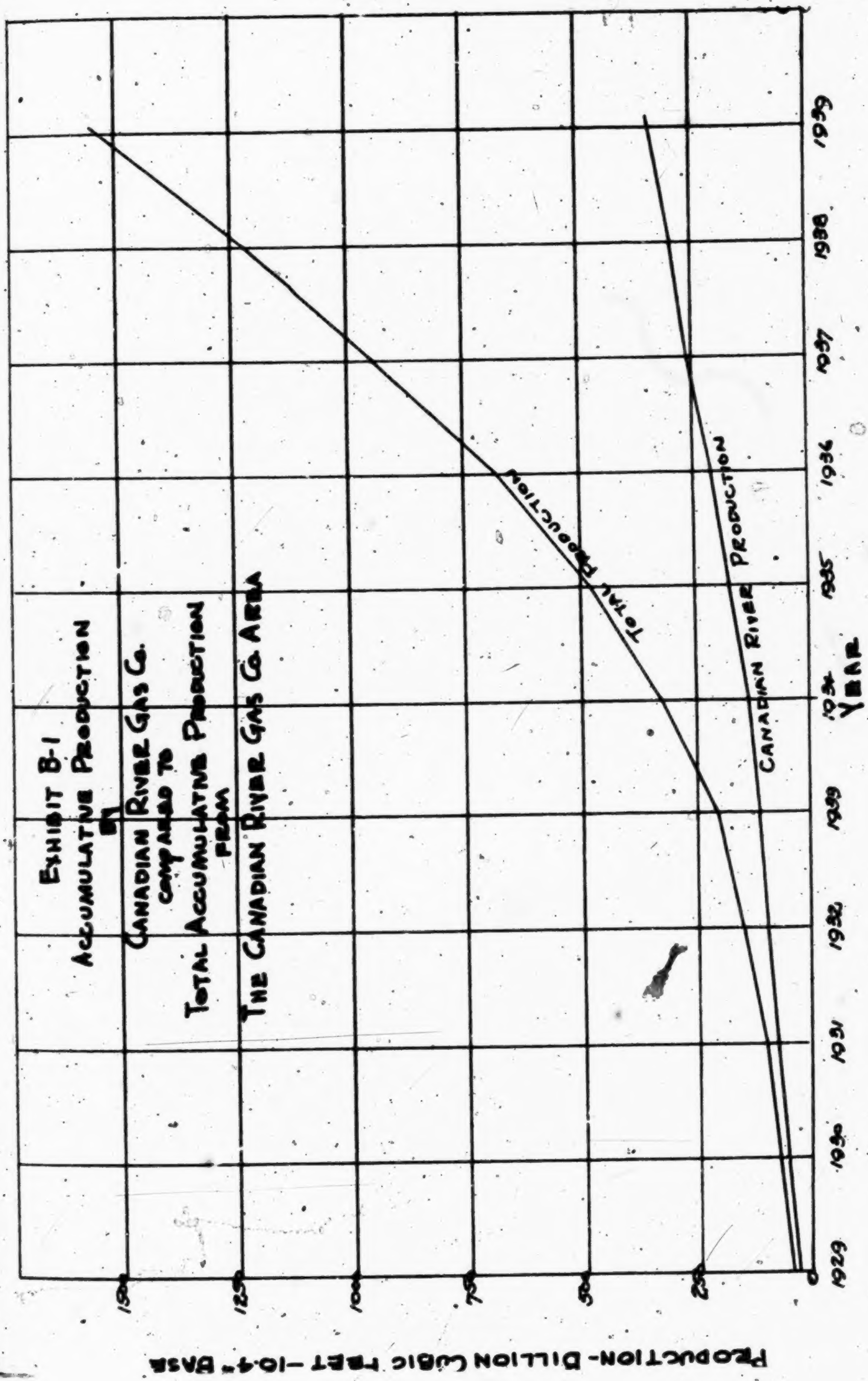


EXHIBIT "B"

ESTIMATED FUTURE CUMULATIVE PRODUCTION

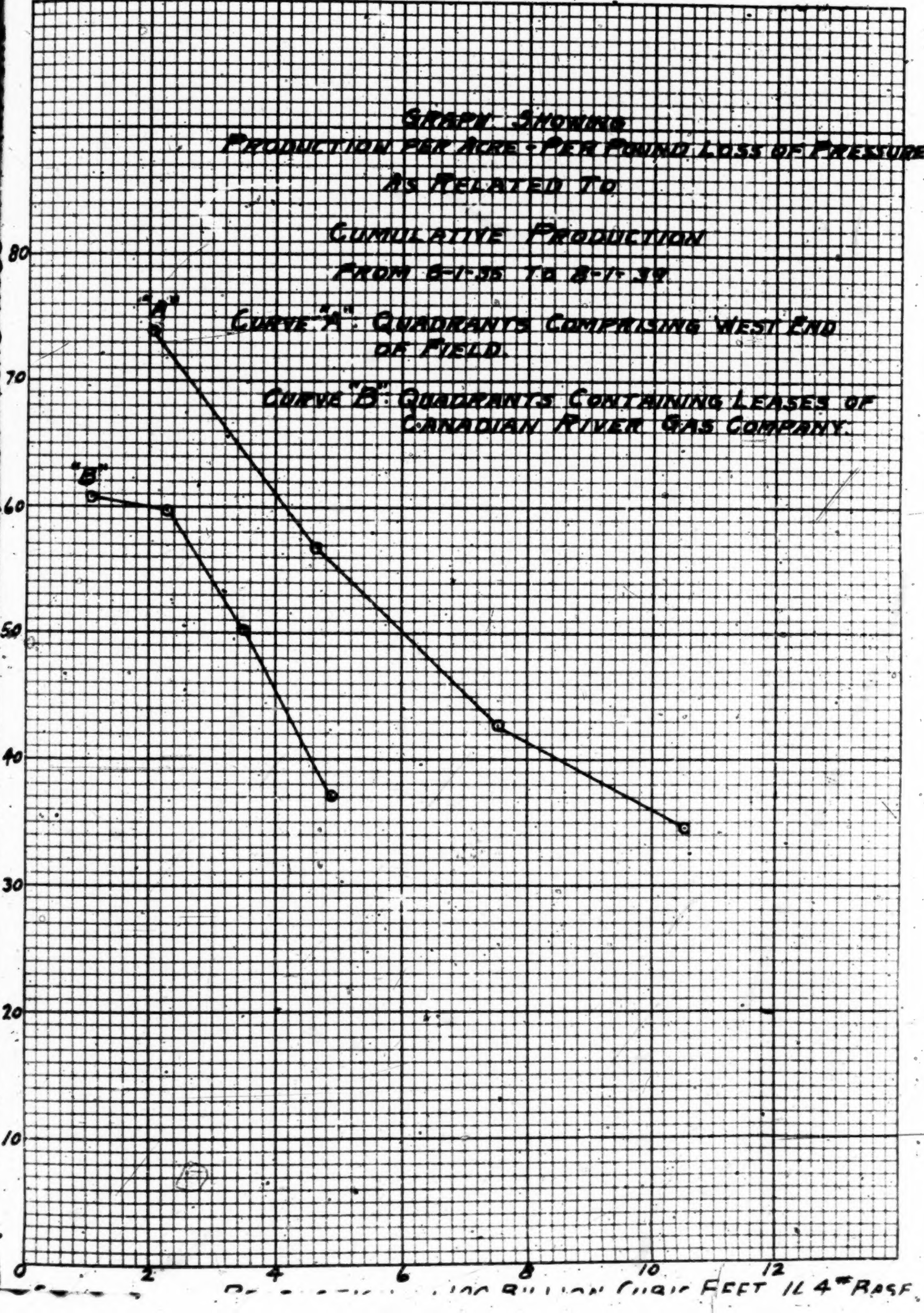
FROM CANADIAN RIVER GAS COMPANY AREA in MCF

Year	By Canadian River	By Others Sweet Gas	By Others Sour & Casinghead	Total Production 16.4#
1940	43,021,625	90,978,797	186,700,000	320,700,422
1941	88,440,132	183,987,652	377,244,000	649,671,784
1942	138,560,820	284,949,842	571,427,000	994,937,662
1943	191,572,243	391,392,117	770,608,000	1,353,572,360
1944	248,106,052	503,819,375	973,361,000	1,725,286,427
1945	307,193,130	620,268,157	1,177,285,000	2,104,746,287
1946	366,280,208	736,716,939	1,381,910,000	2,484,907,147
1947	425,367,286	853,165,721	1,587,003,000	2,865,536,007
1948	484,454,364	969,614,503	1,790,224,000	3,244,292,867
1949	543,541,442	1,086,063,285	1,991,573,000	3,621,177,727
1950	602,628,520	1,202,512,067	2,190,349,000	3,995,489,587
1951	661,715,598	1,318,960,849	2,386,317,000	4,366,993,447
1952	720,802,676	1,435,409,631	2,579,192,000	4,735,404,307

Exhibit No. 256

4713

Exhibit No. 257



J. B. MASSA further testified on cross examination (Vol. 89, pp. 13408-13414; 13416-13419; 13505-13515; 13538-13539; 13542-13544; 13547-13548; 13565-13569) as follows:

Q. If there had been effective drainage by these wells in the large area of the field, Mr. Massa, in the other wells over in the Sanford-Borger area, would not the pressures in all of the wells have been maintained?

A. No, because their rate of withdrawal was greater than the rate of migration and they just couldn't keep up with it, Mr. March. I think that is very evident in the fact that when the rate of production was decreased from the area it has gone ahead and shown up in the form of repressuring of the buildup in pressure for the area. I think it is just as apparent as it can be and I have never heard anybody question the fact there was any migration of gas to the area before.

Q. I am learning things in this case.

A. Yes, sir.

Q. If there had been effective drainage, Mr. Massa, the pressures would have built up or would have been maintained, would they not, without having to curtail the production in those wells to let the pressures build up?

A. There couldn't be maintenance of pressure as long as the rate of production was in excess of the rate of migration, Mr. March.

Q. Why would you ever have a rate of production in excess of the rate of migration?

A. Because—

Q. If you had effective drainage, that could not ever exist, could it?

A. Because of your difference—flow conditions out of a well bore through a formation.

Q. We come now to the obstacles.

A. Certainly, that is not a big can down there.

Q. And it isn't a big ice cream soda. The container has many obstacles which prohibits the free movement of the gas from the low pressures to the high pressures, doesn't it?

Mr. Spencer: He would have said that a long time ago if you had asked him, Mr. March.

The Witness: There is no flow through that reservoir like there is in your ice cream soda.

By Mr. March:

Q. Have you made a study of the geologic conditions, the formations through which the gas flows, to ascertain the rate of flow from one portion of the field to another?

A. No, sir, I have not attempted in any way to evaluate the quantity of gas that has migrated. I have simply pointed out by virtue of difference in pressures the fact that the pressures have increased and there must be a migration of gas in that direction. I have not evaluated it.

Q. Look at those averages there. They have all happened since 1936 and 1935, have they not?

Mr. Spencer: You are referring now to Exhibit 259?

Mr. March: Yes.

Q. They go all the way from one pound—I see one 57-pound well and one 46-pound well. That is the highest, 57 pounds?

A. Yes.

Q. From one to 57 pounds. Mr. Massa, don't you think that is a very very small increase in pressure considering the tremendous decrease in the production from those wells?

A. A buildup, Mr. March, of 57 pounds would represent approximately one-eighth of the gas in place under that land.

Q. How do you know how much gas was originally under the land?

A. I was talking in reference to pressures entirely. 57 pounds is about one-eighth of 430 pounds.

Q. Then you think you can tell how much gas is in place by plotting your production against pressure declines, is that right?

A. I have not evaluated it and I have not stated it in cubic feet at all. I have simply said that it represented one-eighth of the gas originally in place.

Q. Do you think you could use the pressure decline method in ascertaining drainage to and from an area?

A. Only as an estimate, not definitely. You can get ideas from it but I wouldn't attempt to and I have not attempted to evaluate the drainage that was there because of the fact that it does throw you too many curves. I have played with it too much.

Q. You have played with it too much?

A. Yes, sir.

Q. Well, 57 pounds is the highest pressure you have here, the highest increase in pressure. How much would you say one pound was of the gas originally in place there?

A. One 430th.

Q. You think the pressure decline method works like that in showing drainage? Do you think it really does?

A. It works like what, Mr. March?

Q. It enables you to tell how much gas has been lost there?

A. I have told you I haven't attempted to put any evaluation on it as I simply stated it showed the trend. No, I wouldn't attempt to evaluate it. I can give you some figures and let you draw your own conclusion, but I don't say they are right, because they jump around too much. If Boyle's Law is applicable, it would necessarily come out a constant figure.

Q. Have you ever made an estimate of reserves of the Texas Panhandle field?

A. No, sir.

Q. Are you a geologist?

A. No, sir.

Q. What are you? What is your profession?

A. I am a natural gas engineer.

Q. A natural gas engineer?

A. Yes.

Q. Did you ever have a course in geology?

A. No, sir.

Q. Do you think you have ability enough and your background enables you to make any interpretation or appraisal of the drainage conditions in the Panhandle field of Texas?

A. As relates to flow of gas by virtue of differentials in pressure, I think that I can very definitely say that I am not familiar with the flow of gas by virtue of the differential of pressures. I have not attempted to put a quantitative value on what these things will do because there are too many changes that can take place and the thing is not established enough to a definite trend to know where you can set a quantitative value on it.

Q. If the pressures will only increase this much, would you attempt to say how much gas had drained to the area?

Mr. Spencer: He has said time and time again he is not evaluating it as to quantities.

Mr. March: I want to know if he would do it as an engineer.

Mr. Spencer: I object, Mr. Examiner, as he has explained that very fully.

The Witness: I think I told you, Mr. March.

Mr. March: He has done plenty of evaluating. He has said there is drainage, and I am going to make him prove it.

Mr. Spencer: He has done that already.

Mr. March: He shouldn't make statements in his exhibit—

The Trial Examiner: There is no use in repeating the question, Mr. March.

By Mr. March:

Q. As an engineer, I want you to state how much drainage there has been in the area where you have the small increases of pressures in those wells, just whether you would attempt to do it. Would you?

A. I wouldn't attempt to do it on the basis of those pressures alone.

Q. These pressures alone show there has been little drainage in the area, doesn't it?

A. It is taking the fact that the increased buildup there would indicate a small thing, but when taken into consideration with the production during the period of time that those pressures were building up and back down to their low pressure periods, it would indicate a greater quantity. There is no way of evaluating this buildup and the only evaluation I could place upon it would be the volume of gas produced between the high and the low pressure or between the low and the high pressure, and then that this additional value has accrued for it, but we have no way of evaluating it because we have no definite and established amount of gas per acre pound.

Q. You mean originally?

A. Yes, sir.

Q. I thought your geologists told you that.

A. I am talking about it from my own knowledge, Mr. March.

Q. Oh, your own knowledge. I see:

A. In relation to the other factor, I would have to take it in conjunction with someone else's study.

* * * * *

Q. Now, my question is this, Mr. Massa. I want to know whether or not the pressure band of 380 to 360 pounds shown on Mr. Thompson's exhibit is due to withdrawals in that band or whether or not the decline is due to drainage.

A. I haven't studied that particular area. My study was made on a regional basis. I didn't use the smaller contours. It is true enough that they show in several instances local lows, but in considering the thing from a reional point of view, the wider contour bands give a better picture. I grant that those local lows there, that there is a movement of gas locally to that area.

Q. My question doesn't include that, though. My question is this: You made a voluntary statement here that the drainage of the *Sandord* area was now being reflected back up here in the Texoma acreage up in central Moore County in this 380 to 360 pressure area up there.

Now, I want to know whether or not of your own knowledge—

A. Did I say that?

Q. I understood that you did. Did you say that?

A. I don't think so.

Q. Then you are not contending that that area was drained by the Sanford area?

A. I contend that the Sanford area has had its effect. but I wouldn't say that the entire thing was responsible—that the Sanford area was responsible for the entire drop of pressure in there.

Q. I want to know this: whether or not you are able to state here of your own knowledge whether or not the pressure decline in the 360- to 380-pound band in central Moore County has been due to the intensive withdrawals since 1935 or due to drainage. Can you say positively?

A. I have made no study of that contour band there.

Q. I know, but you—have you made any study of the low pressures that have been created there in central Moore County in that Texoma acreage there?

A. As related to central Moore County?

Q. That's right.

A. No. I have given consideration to the rates of production in relation to the pressure loss—

Q. Are you through?

A. I was trying to state something.

Q. Excuse me.

A. I have given consideration to the decreasing rates of production per acre pound loss of pressure, Mr. March, and as I say, I made my studies from the Commission's pressure map and I have not studied that 260 to 280 pound band particularly or any other pound band. As a matter of fact, I didn't study it by pressure contours. It is more or less an area proposition.

Q. So, therefore, you can't state whether or not the pressures went down in Central Moore County because of the intensive withdrawals since 1935 or because of drainage?

A. Not any given spot in central Moore County, no, sir.

Mr. Keffer: Mr. March has asked a question two or three times referring to central Moore County and Texoma as to all of the acreage in that area owned by Texoma Natural Gas Company. I don't know as it makes a bit of difference, Mr. Examiner, but I do want the record straight on that and I would like to ask the witness if there are other companies producing in that area other than Texoma Natural Gas Company.

The Witness: Yes, there is some other production in there.

Mr. Keffer: What other companies produce large volumes of gas in that area other than Texoma Natural Gas Company?

The Witness: *Primcipally* Shamrock Oil & Gas Corporation and Panhandle Eastern.

Mr. Keffer: That is all I wanted.

Mr. March: All right.

Q. I want a little something now. Texoma produces most of the gas in that area you are referring to, don't they?

A. Yes, sir, I think Texoma is by far the largest producer of gas in that area.

Q. Their most prolific area is located in that band of 360 to 340 pounds in central Moore County, isn't it?

Mr. Lange: You are referring to Exhibit 187?

Mr. March: Yes.

The Witness: By "prolific acreage," you mean what?

By Mr. March:

Q. Prolific production. Most of their production comes from there. Their best acreage is located there.

A. I haven't studied it as to that particular point of production, Mr. March. They do have a large production in Moore County. As I said, I haven't studied it as to minute points of that sort.

Q. And you haven't studied the field at all on 20-pound contour pressure bands?

A. No, sir.

Q. And since you haven't done it on 20-pound pressure —contour pressure bands, you haven't done it on 10-pound contour bands?

A. No, sir.

Q. The only thing you have studied is these 50-pound bands of the Railroad Commission put in by Mr. Dunlap?

A. The Railroad Commission maps from which Mr. Dunlap's maps were reproduced are on 50-pound isobars.

* * * * * *

Q. Now we come to Exhibit 257. I refer you first to this curve you plotted over here, the last curve. Where did you ever hear of a curve like that before? Did you ever hear of a curve being plotted like that before?

A. Yes, sir.

Q. Where?

A. The rate of production curve is quite a common curve.

Q. Quite a common curve? When did you ever use such a curve like this in any other hearing or any place else?

A. I have used them in working in my office quite often. I don't know that I have ever used one in a hearing.

Q. This is the first time you have ever used one in a hearing, isn't it?

A. I don't know that I have ever used one before.

Q. Did you ever hear of one being put in a hearing before?

A. I don't know that I have, however, they could have readily have been and I wouldn't have heard of it.

Q. Let's see if I can understand what you have done

there. You have two curves, A and B, so you plot first—I will go through the three things I understand you did—you plot your gas withdrawals over one year against your gas taken out over several years; you plot one acre against many acres. I have calculated here as far as Curve A is concerned, you have plotted one acre against 790 thousand acres in regard to Curve A, and approximately 443 acres in curve B; then you plot one pound against the pounds lost for the production involved, is that right?

Mr. Spencer: Mr. Massa—

The Witness: I don't think it is, Mr. March, as nearly as I could follow you.

Mr. Spencer: Take it step by step.

By Mr. March:

Q. On your vertical tangent here you have production per acre in Mcf., 16.4 pounds per pound loss of pressure.
A. That is right.
Q. Then over on your horizontal—
A. In other words, that is the rate of production per pound loss of pressure, rate of production per acre.
Q. The rate of production from one acre?
A. That is the average rate per acre. It is the average.
Q. That would be one acre. What would it be for one acre?
A. And it would be the average for each acre over the whole area.
Q. That is what it would be for the average acre?
A. For the average acre and each one of the acres.
Q. But you use the word "per" which is the average acre. You are speaking of one acre?
A. It is the average acre. It refers to one acre or all of them.
Q. You referred to pounds lost; do you mean one pound lost?
A. Every pound loss per one acre.
Q. Average pound loss per one acre?
A. Yes, sir.
Q. Per one year?
A. For volume of gas produced.
Q. For one year?

A. It is an annual period that is represented there; however, the yearly periods on the chart are not uniform and are not controlled by time but by volume of gas produced during the year.

Q. But in so far as time is concerned in your vertical tangent it is one year?

A. The rate is for the gas produced during a given year. Each point represents a rate for the year previous.

Q. You plotted that against the cumulative production in one hundred billion cubic feet of gas at 16.4 pounds base?

A. That is right. The points are plotted to show the volume of gas produced at each given rate.

Q. Isn't that the same thing as—if it isn't, I want to know, and I am not trying to be funny—the same thing in that a hen lays in one year against the number of eggs she has laid in her lifetime?

A. You could plot a production rate on eggs, I believe.

Q. Isn't that a homely illustration of what you have done here? You have plotted cumulative against yearly, have you not?

A. That is quite true; however, there are no natural laws governing the rate of production of eggs per year and there is a natural law governing the rate of gas production per pound loss of pressure.

Q. Of course I could argue that, but what natural law is it that governs the per pound loss of pressure?

A. Your Boyle's Law.

Q. I thought you said Boyle's Law didn't work in the Panhandle field, or did you say that?

A. I don't think that it does and I think the graph shows it doesn't.

Q. Yet you used Boyle's Law to show that Boyle's Law didn't work?

A. To show that it is not applicable for the purposes for which it has been used.

Mr. Spencer: In the Texas Panhandle field?

The Witness: In the Texas Panhandle field.

By Mr. March:

Q. You have used Boyle's law to show that?

A. That is correct.

Q. I want to ask you this question: if Boyle's law does-

n't work in the Panhandle field, how can you use Boyle's law to show it doesn't work in the Panhandle field?

A. Just as I have used it here, Mr. March. If Boyle's law was applicable, instead of having these declining lines on this graph you would have a horizontal line and this is simply a method—

Q. Have you ever plotted in a field the production as you have plotted it here to determine whether or not Boyle's law would work in any given field?

A. No, sir.

Q. In the manner you have done it here?

A. I have seen this graph used to illustrate the accuracy of a curve to prove it in various articles.

Q What articles?

A. Different articles I have read from time to time.

Q. Did they teach you this in school in text books that it was a good way to show Boyle's law wouldn't work?

A. No, I don't think that they did.

Q. Did you ever see anything like this in a text book?

A. I don't recall that I have offhand.

Q. Who told you about this curve—Mr. Gill?

A. No, sir.

Q. You devised the curve yourself?

A. No, I have seen the curve used before.

Q. Who used it?

A. The reason I plotted this curve in this manner, Mr. March, is for the purpose of comparison of two areas. There is nothing so complicated about it. Had this curve for an area been of uniform acreage, it would not have been necessary to reduce the vertical ordinate to acre pounds but we could have stopped at pounds because it would have been a uniform area that we were comparing, but simply for the purpose of being fair in the comparison of the two curves, I reduced it down to a common denominator of acres. That is all the difference. One would be the lowest per pound and the other would be the lowest per acre pound.

Q. As I notice your exhibit, the first paragraph of it, it doesn't say anything about it showing Boyle's Law doesn't work. You are trying to show, as I get it, that you have a greater rate of production loss per pound in the Canadian River area than you do in the entire west of the field as you have delineated it.

Mr. Spencer: You brought that out on cross examination.

Mr. March: I just started the cross examination on this exhibit.

Mr. Spencer: You say that if Boyle's law doesn't work why use it here. You brought that up, Mr. March.

Mr. March: He says this exhibit has been prepared for the purpose of showing that in future years it is reasonable to expect that the volume of gas produced per pound loss of pressure will be smaller than the past and present rates of production per pound loss of pressure, and over on Page 3 he says "Due to the fact that curve B representing the area of the Canadian River Gas Company's leases is declined at a greater rate than his curve A, representing the western end of the field, it is reasonable to conclude that the leases of Canadian River Gas Company will produce a smaller volume of gas per acre pound loss of pressure than the average for the western zone."

Mr. Spencer: My only point is that you started into the discussion of Boyle's law by asking if he hadn't said that he didn't agree with Mr. Boyle; if Mr. Boyle's law wouldn't work, and that is the way he got on it—

Mr. March: I will ask the witness this:

Q. I will ask you if you applied any of the fundamentals of Boyle's law in any of the curves you drew?

A. Mr. March, your Boyle's law is the relation of the volume of gas under given pressures and the relation of gas production in pressure drop is necessary to base your Boyle's law as involved, and on this, as I say, under Boyle's law the production of a given amount of gas should bring about a uniform drop in pressure constantly or approximately so.

Naturally, you don't expect to get a perfectly straight line in a field that size, but where the rate is constantly declining it appears that there is some unknown there that is throwing Boyle's law off because Boyle's law is based on a uniform container.

Q. You say you wouldn't expect it to be exactly a straight line in a field that large?

A. No, sir, but I wouldn't expect declines such as this. In constants you would expect a variable line up and down.

Q. If you had a line like that you would say that Boyle's law was working fairly well?

A. I think if you had a constant line with not too much variation in it, there would be some logic in drawing a line through your points above and below.

Q. Have you ever in all your experience plotted the yearly decline in Canadian River's acreage against the yearly production from the wells in that acreage?

A. For Canadian River leases themselves?

Q. Yes.

A. No, sir.

Q. How do you know, if you didn't plot your pressure against your production in the Canadian River leases themselves, that you wouldn't get over a period of time a line which does go up and down but approaches a straight line on the average?

A. The same data can readily be plotted in that manner, and from this curve here you can readily see that it would not be a straight line as it would be—

The Trial Examiner: Which curve?

The Witness: Curve B.

By Mr. March:

Q. But this curve is not a plotting of your pressure decline against your production, it is a plotting of two unlike things against one another as I see it, because you plot production per acre Mcf. at a 16.4 base against cumulative production.

A. Mr. March, in plotting—

Q. You have production in both of these tangents here.

Mr. Spencer: Are you going to let him complete his answer?

Mr. March: Yes.

The Witness: In plotting production or pressure loss against production in order to obtain a straight line you would have to have a constant rate of production per pound loss to do it. This is production per pound loss or per acre pound loss brought down to an acre basis for the purpose

of comparison of curves A and B which are different areas, different sized areas.

By Mr. March:

Q. Do you have any idea of what sort of a curve you would have gotten if you had applied Boyle's law to the Canadian River wells and acreage alone and plotted your pressure decline against your production? Have you any idea what sort of a curve you would have gotten there?
A. No, I have never plotted their acreage.
Q. It looks to me like you have done quite a bit of experimenting in plotting these two curves here that you have in this exhibit.
A. A lot of experimenting?
Q. Yes, to find out the appropriate manner in which to plot it.
A. I don't get your point.

Mr. Spencer: Mr. Examiner, I object as to why the witness didn't prepare some other exhibit than he has prepared.

Mr. March: I will withdraw the question.

Q. As I gather, you are trying to show here that since the Canadian River curve declines at least some faster than Curve A that the Canadian River acreage is being drained by the rest of the acreage in the field, is that what you are trying to say?
A. I think that drainage has its effect and I think that the variation and the original per acre content has its effect.
Q. You think that the Canadian River has less per acre content to begin with than the rest of the west portion of the field you have delineated here?
A. I would not say of the Canadian River's acreage as a whole but undoubtedly from what has happened to these curves since 1937 there is very intensive drainage or a variation of the per acre content. In other words, the effect of withdrawals is reaching out into the edge acreage which is likely to be found to be less productive than the others.

• • • • •

Q. All right, now, back to Exhibit 256. Mr. March spent some little time with respect to the pressure drop in the southwestern part of Hutchinson County and in what you might term the four center areas around there.

Now, I will ask you whether it is a fact or not that that area, the southwestern portion of Hutchinson County, as production continued in there, that it did not necessarily gas in by migration of gas to the southwest; that is, gas from the southwest was moving into that area?

A. I think it is in the general trend of migration from the contour lines and being at a lower pressure there has naturally been gas going that way and the pressure has been maintained to some extent due to it.

Q. The gas has been going out on the other side, hasn't it?

A. Most likely.

Q. That is right. Now, as a matter of fact, whether pressures declined a little or greatly in that area, does not necessarily mean that it was not losing gas to the northeastward in the Sanford area?

A. I wouldn't think so.

Q. Because you have this drainage situation on the other side, that certainly is replenishing some of the loss, isn't it?

A. Yes, sir, your movement of gas cannot be restricted to any small area. The farther away you go from any well bore the area being drained by that well increases and the same can be said of the Sanford area, the Sanford-Borger area; the more it spreads out the greater becomes the area as it gets away from that. It can't be draining from one well to another or one minute area to another. It can't very well be considered in arriving at the mass movement of gas that necessarily occurs from a high to a low pressure area.

* * * * *

Q. Does the fact a producing well is losing pressure mean that it is also not receiving gas by drainage from higher pressure areas? In other words, maybe I didn't state that clearly.

Is it possible for a well to be receiving gas by underground migration even though it shows a reduction in pressure from year to year?

A. Yes, sir. Where your pressure drop is very slight in relation to volume of gas produced, it is quite logical that there is migration of gas to that tract.

Q. Isn't it a pretty safe assumption that any well in a

low pressure area is receiving some gas from the high pressure areas adjacent?

A. There is no doubt that there is gas flowing there, and as to whether or not they are retaining it is something else. There are all kinds of things that come in there. Your ratio of production to migration would be the whole thing. Of course there is gas flowing to the lease.

Q. Now, Mr. March, also asked you if you had studied the area which you have under consideration in your two exhibits with respect to the contour lines existing. As I recall it, you answered that you had made no specific study with respect to specific and particular segments between any two certain isobar lines. Is that correct?

A. That is true.

Q. But the figures which you have utilized in your Exhibit 257 were taken from Mr. Hammer's figures which were based upon his 10-pound isobar line contours, were they not?

A. Yes, sir, the figures in Exhibit 257 came from Mr. Hammer's 10-pound—his data was all taken from that map, as I understand it.

Q. As he computed it?

A. Yes, sir.

* * * * * * *

Q. There has been some question also about the drilling of new wells in the western portion of the west Panhandle field which you have referred to as the Canadian River area. Can you give me just briefly the drilling in that area for the last three years as compared to the drilling in the entire Panhandle field as a whole, east and west included?

A. In 1938 there were 53 wells drilled in the area as compared to 107 wells in the field, or 49.5 per cent of the wells drilled in that area.

Q. What was it in 1939?

A. In 1939 there was a total of 58 wells drilled in the Canadian River area. In referring to the Canadian River area here I mean what I designated in my Exhibit 256 as the Canadian River area. There were 58 wells compared to 98 wells for the field as a whole, or 59 per cent of the wells, and in 1940 there were 63 wells drilled there as compared to 94 total for the field, or 67 per cent.

Q. When you say the field, that includes the east field and west field, doesn't it?

A. Yes, sir, that includes Wheeler County.

Q. What was your drilling in 1940 with respect to sour gas wells?

A. There were 34 wells drilled in the area as compared to a total of 39, for the field.

Q. 39 sour gas wells included in the entire field and 34 are in the Canadian River area, is that correct?

A. That is correct.

Q. You made an estimate of how many sour gas wells would be drilled in 1940 and I am wondering if you missed that very far.

A. I used an average figure throughout the 7-year period of 32 wells.

Q. In the first year there were 34 wells?

A. Yes, sir.

* * * * *

Q. Have you ever made a study of the effect of Texoma wells upon the decline of pressure in Moore County?

A. Texoma wells?

Q. That is right.

A. No, sir.

Q. When did you prepare this Exhibit No. 260 showing the 1940 pressures from wells were remaining stable or increasing?

A. I prepared that with Mr. Thompson when I came back.

Q. Did Mr. Thompson prepare that or did you prepare it?

A. I helped him prepare it. We prepared it together. I got the production data.

Q. You got the production data?

A. Yes, and then I helped.

Q. Did you also get the production data of these wells for 1935 and compare them with 1940?

A. No, sir. I have 1940 production data.

Q. Do you know whether or not 1935 production was a lot more than the 1940 production?

A. Yes, sir; I so stated this morning that the production in 1935 and 1936 was much in excess of the present rates and that the fact that these wells were now repressuring was due to the difference of ratio that existed between the production and migration.

Q. Due to the production and the taking of gas from these wells?

A. Yes, sir.

Q. You haven't implied here that if you had included all of the Hutchinson County, and both the Sanford and Borger areas in your calculations of the Canadian River?

A. Sir?

Q. You have implied here on redirect examination as I understand it if you had included the Sanford area and the Borger area in the Canadian River—

Mr. Keffer: It wasn't that at all. It was all of Quadrant 3, Hutchinson County. He testified to that simply because you complained he had not included all of Quadrant 3, Hutchinson County.

By Mr. March:

Q. As a matter of fact you did include all of Hutchinson Quadrant 3 when you *hade* your curve B didn't you?

A. In Exhibit No. 257 all of Quadrant 3 is included, yes.

Q. According to your own theory then by including that all in Quadrant 3 you tended to decline the crop of the curve?

A. I didn't state that, Mr. March. What I said was that by including all of Quadrant 3, Hutchinson County, which includes some of the wells which are repressured, the tendency is to show a greater production per pound drop of pressure than is shown by the curve—than would have been shown in the curve if it had been left out. In other words, it shows a higher rate of production per pound drop than would have been shown if I had left it out, which is only natural. I don't know what the effect would have been as I haven't calculated it.

Q. You haven't calculated it out to ascertain it?

A. No, but if you have wells that are not *droping* in pressure and you have production from them you are adding to the production without decreasing or without increasing your pressure loss factor and naturally you are taking a greater amount of production and dividing it by the same or a lesser pressure loss and will get a greater production per pound loss.

Q. All of the wells you enumerated this morning are in Quadrant 3, Hutchinson County?

A. No, sir; I didn't say they were.

Q. Did you know in every one of Mr. Hammer's quadrants in Hutchinson County that the pressures are declining and not increasing in spite of the repressuring of some of the wells?

A. I haven't checked them. They may be.

Q. Do you know whether or not in Quadrant 3, Hutchinson County, the pressures are decreasing or increasing?

A. According to the way he has the quadrants laid out and the figures he has used in his quadrants I know the pressure is showing a decline, yes.

Q. It is showing a decline?

A. Yes.

Q. It is showing a decline in spite of the fact that some of the wells have showed a slight increase in pressures?

A. That is true.

Q. Have you made a study to ascertain what has been the pressure drop in Hutchinson County as a whole in 1940?

A. No, sir.

Q. In 1939?

A. I haven't made it in connection with this. I probably did some figuring on Hutchinson County back in 1939 but it wasn't in connection with this study. I figured around on different parts of the field in connection with other things. I don't recall.

Q. Do you know of your own knowledge now whether or not Hutchinson County quadrants are decreasing at a faster rate than Moore County Quadrants or at a lower rate?

A. What part of Hutchinson County?

Q. Do you know whether or not all of Moore County has the pressures declining at a faster rate than Hutchinson County or have you given that any consideration.

A. I didn't include the whole county. I didn't consider —I included part of Hutchinson County in the Moore County area—or study it by county lines.

Q. Then you don't know?

A. No, sir.

Testimony of J. D. Thompson, Jr., Witness for Canadian.

Thompson prepared and sponsored Exhibit No. 187, entitled "Texas Panhandle Gas Field Rock Pressure Map, July, 1939." His direct testimony concerning this exhibit is contained in Volume LXVIII, pp. 9973-9980, and Exhibit 207, pp. 5, 6.

This exhibit shows the extent of the Texas Panhandle Field as outlined by the Railroad Commission. The exhibit further shows 20-pound interval contour or isobar bands, which show the rock pressure conditions existing as of July 31, 1939. These contour (isobar) lines and colored bands are based upon the official wellhead gauge pressures recorded by the Railroad Commission during the summer of 1939.

The following legend which is indicated on the map, shows by colors the wellhead pressure conditions as follows:

	Pounds
Gray	0-200
Orange	200-220
Dark Blue	220-240
Pink	240-260
Green	260-280
Red	280-300
Purple	300-320
Yellow-Green	320-340
Light-Blue	340-360
Brown	360-380
Salmon Pink	380-400
Yellow	Above 400

It will be noted that the areas colored gray, where wellhead gauge pressures are 200 pounds or less, are confined to or adjacent to those portions of the field which produce oil; that the areas colored yellow, where wellhead pressures are 400 pounds or above, are situated in localities remote from the oil producing portions of the field, and, as a result, are generally near the south and southwestern edges of the field.

Thompson stated that originally the entire field had a pressure of 430 pounds at the wellhead. The pressure dif-

ferential, as shown on the exhibit, is the result of progressive depletion of the gas reserves of the field due to gas withdrawals incident to the production of oil and for pipe line use.

The witness also said that in the early life of the field gas was largely regarded as a nuisance which handicapped the development of oil production. There was no market outlet for the gas itself and as a result tremendous quantities were wasted. The earliest producing areas to be developed in the field were the Borger area in south-central Hutchinson County and the Lefors area in central Gray County. In these two areas gas was encountered in pay formations above the oil bearing formations and little interest was taken in conserving this gas. It was frequently allowed to flow from the hole along with the oil and was thus entirely wasted into the air. This situation gave rise to the casinghead gasoline industry. The casinghead plants removed the gasoline content from this gas and popped or vented the residue into the air. Enormous amounts of gas were wasted in this manner. Later the carbon black industry came into the field and utilized this gas. These two industries were, therefore, firmly established and used tremendous quantities of gas from the oil producing areas before the major gas pipe lines were built. These early withdrawals from the oil field resulted in the establishment of the pressure differential picture set forth in Exhibit 187. Without question there has been a tremendous drainage of dry gas from that portion of the field which produces dry gas only to the low pressure oil producing areas due to the long established differential in pressure. That drainage has continued progressively from year to year and is effective today.

The witness on cross-examination testified that at this time there was no effective drainage from the East Panhandle Field to the West Panhandle Field but that the gas in the high pressure area in south Gray County was being depleted by drainage (Vol. LXXVI, pp. 11135-11136), however, a situation might develop where drainage would be possible due to the fact that the east field is losing its pressures rapidly and pipeline companies which are now getting their gas from Wheeler County might build an extension over into the west field and add to the withdrawals from the

west field which would have a tendency to equalize the pressures between the east field and the west field. (Vol. LXXVI, pp. 11136-11137.) Both the east and the west fields are contributing to the repressuring of the oil producing area shown by the gray color in Exhibit 187, in the area immediately north of the block fault in Gray County (Lefors area). (Vol. LXXVI, p. 11137.)

Drainage extends progressively out from a well to higher pressure areas by reason of the fact that gas moves in from the higher pressure areas in order to replace the gas which has been produced. (Vol. LXXVI, p. 11222.) Drainage is a progressive affair. Gas flows from an area of high pressure to an area of low pressure and eventually the effect is far-reaching. (Vol. LXXVI, p. 11224.) Witness, upon being questioned as to the possibility of a well of large open flow draining from the area which contains a well of a low open flow, replied: "Drainage is caused not by the open flow of the wells but by the pressure differential existing." (Vol. LXXVI, pp. 11234-11236.) Production from the wells in southwestern Hutchinson County contributes to the lowering of the pressure in that area and also contributes to the lowering of the pressure in the higher pressure areas to the southwest of them. (Vol. LXXVI, p. 11235.) Canadian wells in the area of southwestern Hutchinson County are not getting their full share of the gas but are only getting some of it as it goes by. The pressure contours change from year to year. There is always a very noticeable change with encroachment of the low pressure southwestward from Hutchinson County into Moore and Potter Counties. (Vol. LXXVI, p. 11242.) The wells in that area contribute to the falling pressures but are not solely responsible. (Vol. LXXVI, p. 11243.) There is no question but that gas is migrating (from Canadian acreage) to the northeast into the Borger-Sanford area. In fact the Borger-Sanford area is actually increasing in pressure notwithstanding the fact that substantial production of gas is occurring in that area. (Vol. LXXVI, p. 11244.) A comparison of the rock pressures in the Borger-Sanford area makes it quite apparent that these wells are building up substantially and if these wells were not receiving gas from an outside source their pressures would not be building up while they were producing (Vol. LXXVI, pp. 11244-11245), and this fact is very significant regardless of whether the

production rate is high or low. (Vol. LXXVI, p. 11246.) The Borger-Sanford area is outlined on Exhibit 187 by a red line. (Vol. XCIV, p. 14365.) Repressuring is now occurring over the entire distance between Borger and Sanford area some eight or nine miles and about two miles west and southwest of the town of Sanford. (Vol. LXXVII, pp. 11280, 11281.) There are very few wells, if any, within the Borger-Sanford area that are not being repressured. (Vol. LXXVII, p. 11285.) The point has finally been reached where gas is migrating into the area faster than it is being produced from the wells. (Vol. LXXVII, p. 11286.) Drainage has a very considerable influence on the shape of the isobars (pressure bands as shown on Exhibit 187.) (Vol. LXXVII, p. 11289.) The shape of the isobars would be different if there wasn't any drainage. (Vol. LXXVII, p. 11288.) Lowering pressures in any pressure band is due both to production of the wells and to drainage to lower pressure areas. It is inconceivable that it is due entirely to production. If it were due entirely to production you would have a series of concentric circles scattered all over the field showing the pressure distribution. This is not true, but on the contrary, you have a great wide sweep of pressure differentials extending from western Moore County across to the Borger and Sanford area. If there was no drainage the concentric circles would appear as is shown on a small isolated area in northwestern Potter County, which is a low pressure area entirely surrounded by higher pressure areas, and in that one area the loss in pressure is due entirely to the production from the one well in the center of the concentric circle and demonstrates that gas is going into the well from every side. (Vol. LXXVII, pp. 11310, 11311.) Drainage into the Borger-Sanford area is very substantial, the gas migrating rapidly enough not only to provide the gas that is being produced but additional volumes of gas. (Vol. LXXVII, p. 11297.) This gas is moving into the area from the higher pressure areas outside of it. (Vol. LXXVII, p. 11297.) These wells are getting more gas by migration than they are producing. (Vol. LXXVII, p. 11298.)

Referring to Exhibit 187, and particularly the Borger-Sanford area, the witness stated that the wells in the Borger-Sanford area which were being repressured are in the orange colored band partially, and it is quite obvious that they are

receiving gas—migratory gas—from the next higher pressured band, the blue band. The blue band, it is obvious, is receiving migratory gas from the pink band, being the one next higher in pressure. Gas displaced from the pink band into the dark blue band is draining the immediately surrounding green band, which is of higher pressure. That gas in turn is being replaced by gas from the red pressure band, which is the next higher in pressure. The matter of drainage is a progressive thing which extends band by band clear out into the extreme portions of the field which are showing pressure decline. The lowering of pressures is a combination of production of the wells through the area and in addition to this, migratory gas is draining from the high pressure area progressively to the low pressure area. (Vol. LXXVII, pp. 11299, 11300.) There are areas that are receiving gas by drainage; that is, migration, and the pressures are still decreasing, which means that such areas are not receiving gas as rapidly from drainage as the gas is being produced. (Vol. LXXVII, p. 11313.)

The witness had been cross examined at length with respect to the migration of gas into the Borger-Sanford area and had stated that there were eighty wells or more in the area in which the pressures were increasing, notwithstanding substantial production from the wells. He later determined that there were 126 wells in the area which were gaining in pressure. (Vol. XCIV, pp. 14362-14364.) These wells are listed upon Exhibit 259. (Vol. XCIV, p. 14363.) Exhibit 260, which is a companion exhibit to Exhibit 259, shows the production from the 126 wells for the year 1940. (Vol. XCIV, p. 14366.)

The production from these wells in 1940 was in excess of 34,000,000,000 cubic feet. The area outlined in Exhibit 187 and which has been referred to as the Borger-Sanford, contains approximately 20,000 acres. Assuming a production, therefore, of around 46,000,000,000 cubic feet for the year 1940 from Canadian acreage, the Borger-Sanford area is producing about three-fourths as much on an acreage basis as the entire Canadian acreage. The Canadian acreage is about twelve times as great as the acreage in the Borger-Sanford area, therefore the rate of production in the Borger-Sanford area is approximately eight times as great on an acreage basis, as the production from the Canadian

acreage, but notwithstanding this heavy rate of production the rock pressure in the Borger-Sanford area is actually increasing and obviously gas is migrating into that area from the surrounding areas of higher pressure. (Vol. XCIV, pp. 14366-14370.)

The Railroad Commission lists a total of 139 wells in the Borger-Sanford area. Thirteen of these wells were ignored because of an erratic pressure history. That is, the pressures fluctuated greatly from year to year and it was obvious that they were not dependable. (Vol. XCIV, pp. 14371, 14372.)

The witness, referring to Exhibit 187 and the pressure isobar bands, stated that gas was migrating out of Moore County and northeastern Potter County in the gneral direction of the Borger-Sanford area; that this picture is shown by the isobar bands on the map and that Commission's witness Hammer's isobar map, Exhibit 179, shows substantially the same thing. (Vol. XCIV, p. 14372.)

Witness also stated that there was a low pressure area extending straight west from the Borger-Sanford area through southern Moore County which he called a pressure ditch and that gas was migrating from both the north and south into this low pressure area and that the gas that was not produced by wells located in the area would necessarily continue to migrate to lower pressure areas in the general direction of Borger and Sanford area. (Vol. XCIV. pp. 14372, 14373.) The flow of gas shown by isobar lines is at right angles to such lines. Pressure differentials west of the Borger-Sanford area are represented by comparatively wide pressure bands, and indicate high permeability of the formations producing the gas and also indicate a comparatively free movement of gas in that area. Just south of the pressure ditch or low pressure area in Moore County the pressure bands in the Canadian acreage are wide which indicates a free movement of gas northward and northeastward, out of the Canadian acreage into the low pressure area of southern Moore County and toward the Borger-Sanford area. (Vol. XCIV, pp. 14374, 14375.)

If you have a tight formation of low porosity or of low permeability, or both, the migration of gas underground is restricted and where you have that situation the pressure

bands or isobar lines on pressure maps are narrow. (Vol. XCIV, p. 14375.)

Movement of gas underground may be rather rapid even though pressure differentials are slight if the permeability is high, for example, if you were taking gas out of one side of a large tank that is 100% permeable, you could get it all without any pressure differential at all and the greater your restriction, therefore, the greater would be your pressure differential and as your restriction becomes less and less, your pressure differentials would become less and less, and you would have a free movement of gas. (Vol. XCIV, pp. 14376, 14377.)

The fact that Canadian acreage in north Potter County and south Moore County is of low productivity does not prevent the free migration of gas because the low productivity may be due to thin pay formations which are permeable. You could still have considerable drainage under these conditions. There is conclusive evidence that this actually happened. The Canadian's Masterson B-5 well did not produce a foot of gas between July, 1939, and July, 1940, yet it lost eight pounds in pressure which is conclusive evidence that it is suffering drainage. This well is comparatively isolated, the nearest well to it being about two miles away and ranging up to six miles to the westward. (Vol. XCIV, pp. 14381-14383.)

Testimony of C. Don Hughes,
Witness for Canadian.

C. Don Hughes, whose qualifications have heretofore been given, testified (Vol. XCIV, pp. 14455-14461) with respect to drainage that Canadian acreage has suffered and is suffering currently, and in that connection he also testified with respect to the original and remaining reserves of the acreage of Canadian.

Hughes' estimates of Canadian reserves on a 16.4 pound pressure base, and after application of a 90 per cent recovery factor are as follows:

Original Reserves		
At 0# gauge	3,126,553,265	Mcf.
25	2,948,648,943	
50	2,763,945,524	
75	2,579,209,882	
100	2,401,337,783	
125	2,216,634,364	
Remaining Reserves on 7-1-1932.		
At 0# gauge	3,010,764,851	Mcf.
25	2,832,860,529	
50	2,648,157,110	
75	2,643,421,468	
100	2,285,549,369	
125	2,100,945,950	
Remaining Reserves on 8-1-1938.		
At 0# gauge	2,793,264,821	Mcf.
25	2,615,360,499	
50	2,430,657,080	
75	2,245,921,438	
100	2,068,049,339	
125	1,883,345,920	
Remaining Reserves on 8-1-1939.		
At 0# gauge	2,719,785 851	Mcf.
25	2,541,8[illegible],529	
50	2,357,[illegible]8,110	
75	2,172,442,468	
100	1,994,570,369	
125	1,809,866,950	

Hughes arrived at the original reserves of Canadian, hereinabove set out, by totaling the reserves of each tract owned by Canadian. He classified all of the Canadian leases, section by section, according to the approximate virgin natural open flow or potential. The potential of each section was then multiplied by the acres it contained and the product multiplied by his factor of .919211. This factor, as heretofore stated, represents the relationship between the approximate virgin natural open flow and reserves per acre in place.

The witness then determined the remaining reserves (as

distinguished from original reserves) by classifying each tract as to pressure existing on the dates hereinafter set out. The pressure was obtained from contour maps. The volume of gas remaining under each tract at each particular survey date was that portion of the original volume in place that the pressure on that particular date bore to the original virgin pressure of 430 pounds. The difference between the remaining volume of gas in place and the original volume of gas in place represents the amount of depletion the acreage has suffered, whether by actual production from the wells located on the acreage or by drainage to adjacent wells, or by a combination of both. The results of these calculations are as follows:

Date	Cumulative Production	Cumulative Depletion
July 1, 1932	94,416,252 Mcf.	115,788,414 Mcf.
August 1, 1938	282,094,343 Mcf.	333,288,444 Mcf.
August 1, 1939	322,364,196 Mcf.	406,767,414 Mcf.

The above tabulation demonstrates that the cumulative depletion has been greater than the cumulative production. The witness stated that it could be definitely concluded that as gas production from the area adjacent to the Canadian leases increases that the drainage will increase. In fact, it is the witness' opinion that the increase in the rate of drainage is just now becoming important. This increase in drainage is due to the increase in production during the last few years from the area adjacent to Canadian leases. It is important to recognize this increase in the rate of production and its effect on drainage in any consideration of the estimated reserves of gas in place under the Canadian leases. It is evident that Canadian will produce only a portion of the gas now in place under its leases.

The witness referred to the fact that from the beginning of production to August 1, 1939, there was produced from Canadian leases 322,364,196 Mcf. and that during the same period the total depletion was 406,767,414 Mcf. The production, therefore, was 79.3% of the total depletion which indicated a loss by drainage of 20.7%. During the period beginning August 1, 1938, and ending August 1, 1939, the depletion was 73,478,970 Mcf. and the production was 40,269,853 Mcf. The production, therefore, was only 54.8% of the total

depletion, which indicates a loss by drainage for this one year of 45.2%. All figures are computed on a 16.4 pound pressure base.

In making the estimates on Canadian leases, computations were made at various dates: 7-1-1932; 8-1-1938 and 8-1-1939. This carried the production performance of its leases back to a date where it is concluded that its withdrawals from its wells alone account for most of the pressure drops in its Area. At that date and on that assumption a factor could be found correlating open flow with reserves however, it results in a slightly smaller factor than Hughes' .919211 factor, but in his opinion, indicates that it is a reasonable factor.

Hughes testified on cross examination that in estimating the reserves of the Canadian, he employed the same method that he employed on the field as a whole; that is, he classified the acreage according to potential and then applied a factor to convert it into reserves in place. It is not a version of the pressure-decline method. The estimate of the Canadian reserves was in more detail since he determined the reserves section by section, each section containing approximately 640 acres. However, some tracts were smaller. Each tract was classified in accordance with the potentials. The study for the Canadian was made subsequent to the time that he prepared Exhibit 212, which was prepared about the first of the year 1939. At the time that he made the study on the Canadian reserves he obtained from the Company a list of all their wells with the open flow of each well converted to virgin rock pressure and corrections were also made for the various size pipe that had been used in the wells so that the figure represented the corrected virgin potential at 430 pounds and at a uniform pipe size. This was the most precise information that he had ever attempted to procure and since it was the latest information he had, he utilized it in making the section by section or tract by tract appraisal of the Canadian acreage. The open flows were corrected very carefully and there is some deviation in this respect from his map, Exhibit 212. The map, however, is not erroneous for the field as a whole because he had also checked it by appraising each section of the field and the figure was so near the figure that would be reached from a

consideration of his zone map that he had no occasion to change it. In other words, differences in open flows on the field as a whole average out pretty well. He could have used his zone map on the Canadian acreage but followed the tract by tract appraisal because he thought it was a little more accurate to do so. (Vol. XCIV, pp. 14477-14486.)

Many tracts over the Canadian acreage do not have wells upon them and these tracts were classified in the light of the nearest wells to them. There were very few sections that had more than one well on the section. There are a few such cases and those sections were not necessarily appraised as to the arithmetical average of the open flows but were appraised with respect to geological conditions in the area. There were a number of those that were considered in appraising a given tract before the actual open flow figure was determined, but if there was more than one well to a section the information on both wells was used; for example, if a section of land had two wells down on one side that were pretty good sized wells and immediately to the north in the next section there was a small well, naturally he wouldn't appraise that section that had the two good wells along the south line according to the arithmetical average potential of those two wells. The small well along the north line would have a bearing on the classification assigned to that particular section. (Vol. XCIV, pp. 14489-14492.) If the section had a well in the middle of it he would not necessarily appraise that section in accordance with the open flow of that particular well. He would be influenced somewhat by the size of the wells immediately around that section. The witness cannot remember precisely without referring to his working papers what he did in each case. The working papers consist of thirteen pages with about 40 entries on each page—in excess of 400 entries in all, and representing approximately 400 tracts of land. (Vol. XCIV, pp. 14493, 14494.) The witness has estimated the reserves on each tract and ... is of the opinion that he secured a correct picture by doing so. (Vol. XCIV, p. 14495.) In estimating reserves for the field as a whole Hughes obtained his remaining reserves at different dates by subtracting the production at the various dates from his estimate of original reserves. He could not do this in the case of Canadian

reserves by reason of drainage away from the acreage. He could do it for the entire field because the field as a whole has no drainage into or out of it. (Vol. XCIV, p. 14501.) The pressure-decline method would work in the field as a whole if you had the proper weighted average pressure; for example, if pressure was weighted on volume of gas in place rather than on acreage, but it does not give the correct answer on the field as a whole where weighted on surface areas alone. (Vol. XCIV, p. 14503.) The witness has assumed that he could apply Boyle's Law to determine the depletion from any particular tract because he had just determined the volume of that particular tract and the depletion would be in the proportion that the pressure of that tract, at the time of the study, bore to the original virgin pressure. (Vol. XCIV, pp. 14505-14508.)

The witness was then asked to compare the original virgin potentials corrected to casing sizes furnished to him by Canadian with the initial potentials of some wells as described by the well logs, which in some cases varied from the figure shown on the well logs. The witness explained that there could very easily be a difference in some cases because frequently the potentials shown on well logs were estimates and were not actual gauges and certainly the well logs would not offer nearly as accurate information as the data which he actually used. He utilized the corrected potentials given to him by the company and he had no reason to question the accuracy of the data furnished. (Vol. XCV, pp. 14511-14518.) Witness also explained somewhat in detail the appraisal of various tracts in accordance with their proximity to the fault line, some of which were below the fault line of the Railroad Commission and some of which were partially below the fault line of the Railroad Commission, and he also explained in detail the effect that surrounding wells have as to the appraisal of a particular tract, and also the influence that acidization or shooting of a well in order to get a higher potential would have on his appraisal. Sometimes the appraisal would be higher and sometimes lower and if the witness had arrived at a higher estimate of Canadian reserves than he did, that this within itself would have shown greater drainage away from the Canadian acreage than his figures do show. (Vol. XCV, pp. 14519-14542.) The witness did not use the open flows as shown on the well logs

because his primary concern was to get the most correct and the latest available information on each well. If later developments showed, as it does in many cases, that the open flow shown on the well log was an erroneous figure, he would have been in error by shutting his eyes to this situation and using a figure taken from the well log, knowing that the figure was an erroneous one. (Vol. XCV, p. 14547.)

The Commission's counsel had marked for identification Exhibit 279, Hughes' working papers, showing the corrected potential used in estimating Canadian reserves, pages 1, 2, 3 and 4. They also had marked for identification Exhibit 280, the working papers of Hughes, page 1 through 13, showing the calculations made as to each tract. (Vol. XCV, p. 14551.) Pressures of different tracts were estimated from the slope of the pressure pattern at that particular point. There were some tracts where the pressures would be uniform throughout and others where the pressure would not be uniform, depending upon the pressure pattern. The actual pressure on each tract was determined by contouring the pressures in the area. The witness utilized a pressure contour map for each of the periods for which the reserve was estimated. The 1939 pressures were taken from Thompson's pressure map, Exhibit 187. (Vol. XCV, pp. 14553, 14563.) The drainage that Canadian has suffered has gone to areas where the pressures were lower than that obtaining in the Canadian acreage (Vol. XCV, pp. 14563, 14564), which would be northeast toward the Sanford and Borger area. (Vol. XCV, p. 14568.) If Canadian had suffered no drainage at all up through 1932 then that would be a very definite indication that the witness' pressure factor of .919211 was too high. If he then corrected his factor and applied a lower figure this would result in a lower estimate of reserves. (Vol. XCV, pp. 14569-14571.)

The witness stated that it was silly to attempt to point to a single well to which gas drained from the Canadian acreage but he did know that the gas drained to areas of lower pressure. The wells in the lower pressure areas are the ones that receive the gas. The lower pressure areas to the northeast receive gas from the Canadian acreage because the nearest low pressure areas were to the northeast and in the Borger and Sanford area. (Vol. XCV, pp. 14574.

14575.) Some of the wells in the Borger-Sanford area have produced staggering volumes of gas and the fact that some of the Canadian Wells in the southwest portion of Hutchinson County produced large quantities of gas resulted merely in those wells getting some of the gas as it went by toward the low pressure area to the northeast around Sanford. (Vol. XCV, pp. 14578-14580.) Gas migrates from areas of high pressure to areas of low pressure, and referring to Exhibit 239, gas would migrate from the yellow area, which is the highest pressure color, to the orange, which is the next lower pressure group, and from the orange to the blue, and from the blue to the green, toward Hutchinson County. That is the only conclusion you can make from the pressure conditions existing. (Vol. XCV, pp. 14588, 14589.) It is the witness' opinion that the Canadian acreage was suffering drainage subsequent to January, 1937, and also that the net effect was drainage away from Canadian acreage for the period from 1932 to 1938. There might be some areas which would be receiving gas as a result of drainage into it but there are certain other areas in which their leases were suffering from drainage during all those years. (Vol. XCV, pp. 14600-14602.) The pressure map for 1934, Exhibit 239, shows that there was a low pressure area around Borger and Sanford and high pressures existed to the southwest into the Canadian acreage. Therefore, the map would indicate that drainage was being experienced from the higher pressure leases of the Canadian located in the area of northeast Potter County, southeast Moore County and northwest Carson County. It is impossible to name a particular well that received the gas that drained away from Canadian acreage but one of the wells was likely the Polo well in the Sanford area which the witness stated had produced fifteen billion cubic feet of gas from one ten-acre lease at the time he made his study. (Vol. XCV, pp. 14602, 14603.) The Polo well is one of the outstanding examples of large production in the area referred to and that anyone familiar with the Sanford area is familiar with the enormous production of this well. The witness does not recall just what period this covered but he thinks it covered the period prior to about 1934 or 1935 and the early production from this well is not reflected by the Railroad Commission's records. No one would contend that any acreage in the Texas

Panhandle Field had as much as a billion and a half cubic feet per acre, which is what this well had produced. (Vol. XCV, pp. 14605, 14609.) The witness reiterated that drainage from Canadian acreage was in the direction of the areas of lower pressure which generally was to the northeast. That one or two wells didn't get all of the gas but the wells that are located between the area of the Canadian leases and the lowest pressure areas obtained it. It is entirely possible that some of the gas has migrated away from the Canadian leases hasn't even been produced yet. (Vol. XCV, pp. 14612, 14613.) The gas that has been lost by Canadian acreage could have been produced by all of the wells that are located in areas of lower pressure. The wells in the very lowest pressure area, which are producing gas without loss of pressure in the Borger-Sanford area, are merely picking up the final bit of gas that has reached that area. Much of the gas that started toward that general area was produced by other wells along the way. (Vol. XCV, pp. 14615, 14616.) Canadian wells alone in the northeast part of their reserves did not produce the gas that migrated from Canadian acreage. If that had been true you would have had a bunch of "sink holes" around those wells (concentric pressure bands). The fact that wells in the Borger-Sanford area began to increase in pressure as their production was retarded makes no difference with respect to the question of drainage; whether the Sanford production was increasing or not, drainage is going into that area, because while the pressures were increasing the wells were actually producing large volumes of gas. If the pressures were static this would still prove that drainage is taking place in view of the production from the wells. If the production is later increased from those wells and the pressures start going down again (Borger-Sanford area) they would still be receiving gas by drainage as long as the high pressure areas continue to exist back to the southwest. It is very likely true that the wells in the Borger-Sanford area are being repressured by local movement of gas into that area but as gas moves from the adjacent area into the next lower pressure area, gas from the next higher pressure area moves in to replace it and "local drainage" finally becomes long distance drainage. The pressures in southwest Hutchinson County have been maintained to a degree, notwith-

standing loss of gas by drainage into the Sanford area, because the higher pressure areas to the southwest are also furnishing gas to this area. (Vol. XCV, pp. 14619, 14622.)

Testimony of Stanley Gill, Witness for Canadian.

Stanley Gill, witness for Canadian, whose qualifications have been stated heretofore, testified on the subject of drainage generally and particularly as it affected Canadian reserves. His testimony on direct examination may be found in Volume XCI, pp. 14023-14027.

Estimation of reserves of recoverable gas is obviously of fundamental importance in determining the future value of a group of gas-producing properties as a source of supply for a major pipe line system. However, reserve of gas in place is not by any means the only factor to be considered in investigating the future life of such gas-producing properties. As a whole, the solution of the problem for a given case involves many factors, but it can be resolved into a few simple elements. These elements relate to both physical and economic factors and are concerned not only with the particular properties under consideration, but also with the effect upon them of operations on other properties withdrawing gas from a common reservoir. These factors are of controlling importance in the Texas Panhandle Field in the case of properties producing gas to supply trunk pipe lines. (Exhibit 265, p. 41.)

It is an inescapable conclusion that the future productive life of wells and properties serving a trunk pipe line will be far more closely related to reserves and withdrawals of gas from the field as a whole than to reserves and future withdrawals from the specific properties in question. The Texas Panhandle gas reservoir constitutes essentially a single inter-connected system of porosity. Although there are differences in thickness and physical characteristics of the reservoir rock in different parts of the field and vertically through the reservoir system, the reservoir in a broad sense is definitely a single system, permeably inter-connected throughout. Therefore, withdrawals, of gas from any part of the reservoir will affect, materially, the gas lying under other far distant parts of the field. Not only do such withdrawals bring about extensive drainage, but they are of im-

portance in controlling future trends of withdrawals. For example, heavy withdrawals of gas from Wheeler County may be expected to lead to permature reduction of pressure, and to a shift of withdrawals into the sweet gas area of Moore County. For a similar reason future heavy withdrawals may be anticipated from what is now a sparsely developed high-pressure sour gas area in Moore and Hartley Counties. (Exhibit 265, pp. 41-42.)

Because of the physical characteristics of gas, it is theoretically possible that a single gas well could eventually drain substantially all of the gas out of the Texas Panhandle Reservoir. This theoretical possibility is of course a practical absurdity because of the great time that would be required, but the reservoir characteristics, which make this theoretically possible, have had a tremendous influence on the performance of the field in the past and will continue to be of controlling importance down to the very end of its producing life. The effects of drainage of gas have been of particular importance in the Texas Panhandle Field because of the manner in which developments have been carried out and the manner in which withdrawals of gas have been distributed. The reasons for concentration of withdrawals along the northern flanks of the structure are so familiar that they need not be described. This concentration of withdrawals established, early in the life of the field, great trends of drainage, which were apparent in the very earliest pressure surveys and which have continued down to the present time. Gas has drained generally toward the north, from the high-pressure sweet gas areas, since the very beginning of oil development in the field, and this drainage may be expected to continue. In some parts of the field, and particularly in Moore County, it is reasonable to anticipate increased development of low pressures in the sour gas area in the future. (Exhibit 265, pp. 42-43.)

During the future producing life of the field, drainage from high-pressure areas to replenish the low-pressure areas will unquestionably continue, since withdrawals of gas from high-pressure sweet gas areas will be limited by the pipe line outlet and will be less in proportion to the high rates of withdrawal in the sour gas area. The conclusion that high-pressure sweet gas acreage will lose tremendous quantities of gas by drainage during future years is absolutely inescapable. (Exhibit 265, p. 43.)

It must be concluded that the future life of gas-producing properties serving gas pipe lines will be determined, not primarily by the reserves of gas which originally underlaid the particular properties or which now underlie them, nor by the future rates of withdrawal of gas from the particular properties in question. Rather, the future life of these properties will be determined by the total reserve of producible gas remaining in the field and by the future rates of withdrawal of this gas for all purposes, not only through wells on the particular properties under consideration, but through all of the wells in the field, wherever they may be located. There will be of course numerous minor exceptions to this generalized conclusion, but its validity as related to any considerable group of gas-producing properties in the Texas Panhandle Field is beyond question. (Exhibit 265, pp. 43-44.)

The situation of the Canadian properties in the field, and the effect upon them of present drainage and of the future drainage trends that may be expected to develop as withdrawals of both sweet and sour gas shift from other parts of the field to Moore County, make the foregoing statement particularly relevant when related to Canadian's holdings. (Exhibit 265, p. 44.)

Additional Canadian
Evidence on Drainage

Gill for the purpose of this study took into consideration all of the information and data set forth in his previous written statement (Exhibit 265) including all of the exhibits and testimony referred to therein, as well as the Commission's Exhibit No. 95 showing the acreage of Canadian in the Texas Panhandle Field. The word "drainage" as used by the witness means the general sub-surface migration of gas by reason of differentials in reservoir pressures within a given field.

The witness' testimony, with respect to the above matters appearing hereinafter, is contained in Volume XCI, pages 14031 to 14049, and in the written statement of Exhibit 266.

Gill stated that drainage inevitably takes place in a gas reservoir comprising an inter-connected porous system, between the various parts of which differences in pressure exist. Because of the low viscosity of gas, such drainage

takes place over very long distances and through formations of relatively low permeability. The gas reservoir of the Texas Panhandle Field is definitely a completely inter-connected porous system, and great pressure differentials were established early in the life of the field as a result of intensive development and production in the oil-producing areas. Subsequent operations, and particularly the withdrawals of sour gas and casinghead gas, have maintained these pressure differentials. The differences in per-acre withdrawal rates that originally established pressure gradients in the Texas Panhandle Field may be expected to continue. This expectation, as it bears upon properties in the western part of the Texas Panhandle Field, has been discussed by Massa in his Exhibit 256. (Exhibit 266, pp. 2-3.)

That the regional pressure gradients in the Texas Panhandle Field have actually brought about sub-surface migration of gas on a tremendous scale, resulting in great drainage of gas from large areas, becomes apparent upon examination of available factual data. This conclusion is grounded upon, and is positively supported by, four lines of analysis of the facts as to field performance:

1. The sequence of development of low-pressure areas from year to year, which is graphically illustrated in the series of isobar maps submitted by Dunlap (Exhibit No. 239), shows the consistent migration of gas into areas of low pressure, and the consequent reduction of pressures in areas of higher pressure.

2. That gas is draining into areas from which there have been heavy withdrawals of gas is conclusively demonstrated by the fact that pressures in such areas have been maintained in the face of continued withdrawals. In some large areas there has actually been an increase in pressure during recent years, despite the fact that substantial quantities of gas have been produced out of them during the period of pressure build-up. Specific data on this maintenance and build-up of pressure are contained in Massa's Exhibits No. 259 and 260.

3. As new wells are completed in the field, they encounter gas at pressures materially lower than virgin reservoir pressure, which is the direct result of prior withdrawals of gas out of other wells in the field.

4. Past pressure declines and past withdrawals of gas as between different parts of the field are definitely related to each other in such a manner as to show that extensive drainage of gas over long distance has taken place. (Exhibit 266, pp. 3-4.)

The most conclusive demonstration of definite regional drainage trends is found in the progressive changes of the field pressure pattern. Major trends of drainage are apparent from an analysis of the series of field isobar maps which were submitted by Dunlap as Exhibit No. 239. For example, the growth of a low-pressure area, resulting from drainage into the Borger-Sanford area, is very apparent from these maps. From year to year this low-pressure area has extended farther and farther to the west and southwest into Moore and Potter Counties. Up to about 1937, nosing of low-pressure contours into this area was caused almost entirely by drainage of gas into the Borger-Sanford area. Since that time the rate of production out of the Moore County and Potter County sweet gas area has increased, but rates of withdrawal of gas out of this area are still much lower in proportion to gas reserves than are withdrawals of sour gas out of the Borger-Sanford area. Continued extension of this low-pressure area since 1937 is definitely shown by the maps and is, to a great extent, the result of continued drainage of gas into the Borger-Sanford areas. (Exhibit 266, pp. 4-5.)

The Dunlap maps (Exhibit 239) also show an important drainage trend in northwestern Moore County. Beginning in 1935, a low-pressure area developed in this section of the field as a result of heavy gas withdrawals. The growth of this low-pressure area from year to year, and the extension of the low-pressure contours into the sweet gas field, are very apparent from the isobar maps. By 1940, drainage into northwestern Moore County had affected a very considerable area, as shown by the 350-pound contour. The low-pressure area from northwestern Moore County had almost met the low-pressure area resulting from drainage into the Borger-Sanford area. It is interesting to note that the development of these low-pressure areas has followed, in general, the zone of high productivity shown on Hughes' map, Exhibit No. 212. (Exhibit 266, p. 5.)

The effects of drainage are also strikingly apparent in the

pressure changes that have taken place in Carson County. There have been heavy withdrawals of gas along the northern part of the field in Hutchinson and northeastern Carson Counties. Withdrawals from the southern and western parts of the field in Carson County have been far lower in proportion to reserves. The progressive development of low pressures in this part of Carson County is evident from the pressure maps. Each map, when compared to that of the previous year, shows that there is rapid development of low pressures. It is significant also that in northeastern Carson County, the area having a pressure of less than 200 pounds has not increased in size since 1938, and that the area having pressures of less than 250 pounds has not shown any great increase in size. The significance of the above condition is, that long-distance drainage from higher-pressure areas is providing gas to the gray and orange colored bands (Exhibit No. 239), to the extent that the pressure drop in these bands is being retarded. Large quantities of gas are still being withdrawn from these areas, but as pressure differentials are set up across the field, gas is moving from long distances to replenish the depleted pay formations. (Exhibit 266, pp. 5-6.)

The fact that pressure gradients develop rapidly as a result of drainage is shown on Dunlap's maps, Exhibit No. 239, by the early pressure performance in Gray and Wheeler Counties. The map for 1934 shows a large area colored in brown in these counties, having rock pressures between 350 and 400 pounds. In the succeeding years the brown color is replaced with colors of lower pressures across the entire width of the field in these counties. Dunlap's map for 1940 shows a large area having rock pressures of 350 to 400 pounds in Moore and Potter Counties. It is to be expected that in future years, with the continuation of heavy withdrawals out of the Borger-Sanford area of southwestern Hutchinson County, pressure performance in this area will be similar to that which was the case in Wheeler and Gray Counties, and that increasing pressure differentials will be set up. Massa's Exhibit No. 256, which discusses the factors that will lead to a shift of production to the western portion of the Texas Panhandle Field, lends emphasis to the probability of this pressure differential becoming a very serious problem in this area. (Exhibit 266, pp. 6-7.)

An interesting comparison can also be made between the isobar maps (Exhibit No. 239) and the curves contained in Massa's Exhibit No. 257. These curves indicate that up until 1937, the production out of wells located in the Canadian Area was almost sufficient to account for the pressure drop which had occurred. Beginning in 1937, pressures in this area began to decline at a far more rapid rate, apparently because material sub-surface drainage out of the area began at about that time. This opinion arrived at by Massa as a result of study of the pressure-production relationship, is corroborated by the isobar lines on the maps submitted by Dunlap. (Exhibit 266, p. 7.)

Reference to Hammer's pressure map (Exhibit No. 179) shows that drainage from southern Moore County and from Potter County is in the direction of the Borger-Sanford area. The pressure bands to the west and southwest of Sanford are comparatively wide. This indicates that there is no effective barrier against long distance drainage. That this condition exists is also emphasized by reference to Hughes' map showing zones of productivity, which indicates that wells in the area southwest of Sanford are in a highly productive area and in an area where the permeability is comparatively high. The drainage condition above referred to is further substantiated by the results of Thompson's study (Exhibit No. 187), which shows that in spite of large production from wells in the Borger-Sanford area, pressures in this area during the past several years are higher than in 1935 and 1936. When pressure differentials are established, as shown by Hammer's map, the inevitable conclusion is that migration of gas will occur over long distances. (Exhibit 266, p. 8.)

It is to be expected that a low-pressure area of major consequence will develop along the western end of the field as the sour gas area in Moore and Hartley Counties is developed. The low pressures in this sour gas area will develop like the low-pressure area in northwestern Moore County, the rapid and progressive growth of which since 1935 is very clearly shown by Dunlap's maps (Exhibit 239). Massa has pointed out in Exhibit No. 256 that the high pressures in this sour gas area will provide the incentive for a rapid extension of sour gas operations into it. Due to the fact that wells of low productivity are to be expected in this area, it appears

probable that pressures will decline there rapidly once withdrawals are started, and that a low-pressure area of considerable size will develop. (Exhibit 266, pp. 8-9.)

The combined effect of continued drainage and of original differences in gas content of different parts of the Panhandle Reservoir is very clearly illustrated by the results of a study of the West Panhandle Field, which was made by witness during 1938. As a basis for this study, estimated withdrawals of gas from the discovery of the field down to January 1, 1938, were geographically allocated to the sections of the West Panhandle Field from which the gas had actually been produced. Although this process involved a great amount of estimation and assumption, it is believed that the final allocation was reasonably accurate. From rock pressure survey data of the Railroad Commission, losses of rock pressure from an assumed original rock pressure of 430 pounds were determined and a map of the West Panhandle Field was contoured with lines of equal rock pressure loss, 20-pound intervals being used. The areas of these zones of equal pressure loss were measured by planimetering, and the amount of gas that had been removed from the reservoir out of wells located in each of the zones was determined from the withdrawal allocation estimates previously described. Production per acre-pound out of each of the zones was then calculated. Results of this calculation as shown in the following table are plotted on a curve attached to Exhibit 266.

Loss of rock pressure from original 430 pounds	Area in Acres	Production to 1/1/38, MMCF. per Ac.-Lb.	Recovery per Ac.-Lb. as percentage of field average yield
0 - 10	124,665	0.0057	8.7%
10 - 30	347,803	0.01443	21.9
30 - 50	216,110	0.0393	59.5
50 - 70	67,437	0.0519	78.6
70 - 90	35,383	0.0264	40.0
90 - 110	32,677	0.0184	27.9
110 - 130	33,715	0.0194	29.1
130 - 150	27,803	0.0149	22.6
150 - 170	28,114	0.0301	45.6
170 - 190	28,535	0.0644	97.5
190 - 210	32,706	0.0522	79.1
210 - 230	24,840	0.133	201.7
230 - 250	19,758	0.0932	141.2
250 - 270	10.653	0.1251	189.8
270 - 290	16,548	0.1788	270.5
290 - 310	6,468	0.1110	168.2
310 - 330	7,335	0.1810	274.5
Over 330	8,506	0.2335	353.5

(Exhibit 266, pp. 9-10.)

The fact that actual recoveries per acre-pound out of the West Panhandle Field have varied over a range of nearly 40 to 1, and that these recoveries have varied continuously and regularly across the field, is strikingly apparent from these data. In effect, the data show the relationship between gas recovered through wells located in the particular areas, and pressure declines which are the combined result of such recoveries out of wells and of losses or gains of gas by subsurface drainage. (Exhibit 266, pp. 10-11.)

Similar disparities in recovery rates for the period August 1, 1935, to August 1, 1939, are reflected in the basic figures used by Hammer for his estimates of reserves of gas (Exhibit No. 180). Results of calculations made by witness from Hammer's basic data for his individual "quadrants" in the western part of the Texas Panhandle Field are tabulated below:

Hammer's "Quadrant" (Exhibit No. 179)	Area in Acres	Production 8/1/35-8/1/38, MMCF./Ac.-Lb.	Recovery per Ac.-Lb. as percentage of average for entire group
Hartley*	32,906	0.03672	64.5%
Potter I*	57,588	0.03888	68.4
Potter II*	44,937	0.02924	51.4
Potter III*	33,389	0.04006	70.5
Moore I*	62,173	0.06249	108.1
Moore II*	61,866	0.03487	61.4
Moore III*	56,614	0.03104	54.6
Moore IV	28,775	0.00854	15.0
Moore V	62,614	0.02134	37.5
Moore VI	79,556	0.03428	60.4
Moore VII	65,530	0.09296	163.7
Moore VIII	29,198	0.11054	195.2
Hutchinson I	9,660	0.35868	632.
Hutchinson II	50,658	0.22683	399.
Hutchinson III*	53,967	0.13077	229.5
Hutchinson IV	46,157	0.00744	13.1
Hutchinson V	35,097	0.01041	183.3
Carson I	52,814	0.00854	15.0
Carson II	82,997	0.09503	167.3
Carson III	79,985	0.05468	96.2
Carson IV*	40,251	0.05544	97.5

*"Quadrants" in which Canadian acreage is located.

Due to the configuration of Hammer's "quadrants," these figures fail to reflect the full, actual variations in recoveries between different parts of the producing area. Even so, the extreme ratio of 48 to 1 between the high and low "quadrants" proves definitely that sub-surface migration on a large scale took place during the period considered. (Exhibit 266, pp. 11-11a.)

The figures arrived at in both of the above studies reflect the effects both of drainage and of original differences in reservoir content. If it could be assumed that the original reservoir content expressed in terms of total gas per acre was the same in all parts of the field, these figures could be used to obtain a quantitative expression of the drainage that

had occurred into and out of the zones of pressure loss up to the time when the study was made. (Exhibit 266, p. 11a.)

Since original per-acre reserves in the Texas Panhandle Field varied widely as between different parts of its area, such a quantitative calculation cannot be made from the figures given in the table. However, these figures demonstrate conclusively that drainage is a major factor to be considered in estimating the future life of the high-pressure gas reserves from which the gas pipe lines are supplied. (Exhibit 266, p. 11a.).

Remaining Life of Gas Reserves of Canadian in Texas Panhandle Field as a Source of Supply for Long Distance Pipe Lines

Testimony of STANLEY GILL, Witness for Canadian.

The witness' general opinions as to the factors determining the economic life of gas reserves serving trunk pipe lines in the Texas Panhandle Field, were presented in his written statement, Exhibit No. 265. His conclusions as to these factors are re-stated in the introduction to this statement on the actual effects of drainage of gas in the Texas Panhandle Field. He is very definitely of the opinion that the useful life of Canadian's gas reserves in the Texas Panhandle Field, as a source of supply for transmission through their lines to distant markets, will be determined to a controlling extent by sub-surface drainage of gas from beneath their properties. This conclusion rests upon the probability, amounting practically to a certainty, that per-acre rates of withdrawal out of Canadian's acreage to meet their pipe line requirements, will continue to be materially lower than per-acre rates of withdrawal out of other parts of the West Panhandle Field. This conclusion is supported by the fact that this acreage is now and will continue to be affected by extensive sub-surface drainage at an accelerating rate. Because of these conditions, he believes that for all practical purposes the economic life of Canadian's gas-producing properties in the Texas Panhandle Field will closely approximate the economic producing life of the field as a whole, and will bear but little relationship to the quantities of gas which may currently underlie Canadian's leases. While it is probably true that pressures in the area operated by

Canadian will be somewhat higher than the field average, down to the very end of their producing operations, it is equally true that abandonment of operations designed to serve a trunk pipe line system will be higher than the average abandonment pressure for the field as a whole, because of the economic factors controlling pipe line operations. Therefore, it seems to the witness very reasonable to assume that the economic life of Canadian's reserves will be determined by the economic life of the Texas Panhandle Field as a whole. (Exhibit 266, pp. 11a, 12, 13.)

Gill stated that by reason of the foregoing, it is his opinion that Canadian will be unable, economically, to supply all of its anticipated market requirements from its gas reserves in the Texas Panhandle Field beyond the year 1951, but that it will be able to supply a portion of such markets at declining rates until about the year 1956, when the economic life of the property for the purposes required by Canadian will definitely terminate. This conclusion on the part of the witness is modified only by his opinion that the economic limitation on development and the economic limitation on producing operations may very probably be reached before the dates stated. (Exhibit 266, p. 14.)

Gill testified on cross examination that the life of the Canadian reserves are far more closely related to the total life of the field than to the quantities of gas currently in place under their particular properties. The witness stated that it would be physically possible for Canadian to recover all of the gas currently in place under their properties by blowing the gas into the air, but as a practical matter they will not ever recover the quantity of recoverable gas which now exists under their properties. The witness stated that Hammer, Commission witness, might have the idea that it would be physically possible for Canadian to recover the volume of gas under its properties, and it may be physically possible for it to do so, but from a practical situation such an assumption is sophistry of the wildest sort. The witness further stated that if he desired to indulge in pure sophistry he would say that Canadian could recover all of its recoverable gas now under its property but it would be necessary for them to drill a lot of wells and blow a tremendous quantity of gas into the air. That as a practical matter Canadian would never recover anywhere near all of the

quantity of gas which now exists under its properties. (Vol. XCIII, pp. 14264, 14266-14269.)

The witness has examined the individual pressure performance of some of Canadian's wells and has examined in some detail the performance of pressures over the Canadian Area as a whole from year to year, and he has related withdrawal pressure performance in the Area involved to withdrawal pressure performance in other parts of the field on production and pressure performance from the beginning down to January 1, 1938. His study has been made not so much with respect to particular wells but with respect to the isobaric contourings of the area which were determined by the pressures of individual wells. The witness has not followed the pressures through from year to year on a specific well because that isn't the important thing. The important thing is the pressure in the area as reflected by proper isobaric contours which is of significance. He has constructed pressure maps of the Texas Panhandle Field at various times and to that extent he has considered the pressures of all the wells. (Vol. XCIII, pp. 14295, 14296.) Upon being asked whether he thought that Canadian could recover all of the gas under its acreage by the present wells within a reasonable length of time he replied that he did not think it would ever recover all of the gas under its acreage out of existing wells, or out of existing wells combined with any wells they might drill. As a practical matter Canadian will never recover anywhere near the quantity of gas which now underlies their leases in the Texas Panhandle Field. The question of how much gas can be recovered out of a given existing group of wells is a question of the period of time involved. Canadian will have to drill additional wells in order to hold their potential production, their open flow, up to a point where it can meet its daily demands. It will have to drill additional wells in order to recover and utilize the quantity of gas which it will eventually recover out of the property which will be much less than the quantity of gas that now underlies the property. Additional wells will necessarily be drilled, not for the purpose of adding anything to the quantity of gas existing under the property, because this would not do it, but of adding to the daily producing ability which Canadian must have to meet its market demands. (Vol. XCIII, pp. 14316, 14317.)

The witness stated that in making an estimate of the

future expectancy of the wells of Canadian it would be necessary to study the probable future life of the Texas Panhandle Field as a whole. (Vol. XCVIII, pp. 14334, 14335.)

The witness reiterated the statement made in his direct testimony that if given a sufficiently long period of time a single well could drain all of the recoverable gas out of any permeably inter-connected porous system, even though the size of the system was as great as that of the Texas Panhandle Field, and that the reservoir characteristics which makes this theoretically possible have had a tremendous influence on the performance of the field in the past and would be of controlling importance down to the very end of its producing life. (Vol. XCIII, p. 14321.)

Gill then was referred to the series of pressure maps prepared by Dunlap (Exhibit 239). He was then asked if he had studied the individual production from individual wells in each one of the pressure bands to ascertain whether or not the movement of the particular pressure bands from year to year is due to drainage or production within the area. The witness replied that he had not made a specific study band by band as to those particular maps but that he had made those studies generally in the field and was thoroughly familiar with the general facts as to the gas withdrawals. He has studied the withdrawals from various parts of the field in sufficient detail to state very definitely that the pressure changes, as reflected by the maps, are caused by drainage. His only detailed study with respect to pressure bands and the movement of the same, is summarized in the written statement in Exhibit 266 and in the table on page 10. The witness stated in his direct testimony, as shown by page 10 of Exhibit 266, and the table in connection therewith, that actual recoveries per acre pound out of the West Panhandle Field have varied over a range of nearly forty to one, and that these recoveries have varied continuously and regularly across the field. The data contained in the table shows the relationship between gas recovered in various pressure bands. It will be noted that where the loss in pressure, for example, has been only ten pounds, the recovery per acre pound has been only 8.7% of the average yield for the field as a whole, and where the loss in pressure has been over 330 pounds, the

recovery per acre pound has been 353.5% of the average yield for the field. In other words, the lowest pressure area in the field has recovered approximately forty times as much gas per acre pound loss in pressure as the highest pressure area in the field. The witness stated that much of this discrepancy in the rates of recovery is due to subsurface drainage of gas. (Exhibit 266, p. 10.) Slight changes in the form of the pressure contour bands (isobars) on the Railroad Commission's maps from year to year is of very little importance. The important thing is the general trend as shown by the large features as to pressure changes. Looking at the entire series of maps there is shown a great over-all eating back of a low pressure area into Moore and Potter Counties from the Borger-Sanford area. This indicates a great drainage trend, although there have been local effects within the area. It is entirely possible that some portions of Canadian acreage would pick up some gas out of other parts of Canadian acreage. The high pressure area in Potter County represents acreage of Canadian from which much of the drainage would necessarily come. The witness has made a study to determine physically the cause of the over-all sequence of development of low pressure back into Moore and Potter Counties. Very definitely that general over-all development is occasioned by the large regional drainage of gas out of that area into the area of very heavy withdrawals which lie generally in southwestern Hutchinson County. The tabulation on page 10, Exhibit 266, (hereinabove referred to) shows very positively that the Canadian acreage in Potter and Moore Counties has suffered extensive drainage. (Vol. XCIX, pp. 15295-15300, 15325.)

Gill stated that Dunlap's series of pressure maps, Exhibit 239, do show exactly what has taken place when considered in general as to broad details which reflect the trends of drainage in the sequences that are shown from year to year. The series of maps show very well and very thoroughly that drainage has occurred. (Vol. XCIX, p. 15302.) Witness again reiterated that the study of individual wells would have no bearing with respect to the question of regional drainage. It is true that the gas that was withdrawn came out of individual wells, but it is the average withdrawals over large geographical units that prove conclusively that the extension of low pressure back into Moore and Potter Counties is the result of drainage of those areas. The low

pressure area extending out from the Borger-Sanford area didn't reach over into Potter County instantly. The effective drainage into the Borger-Sanford area was beginning to show up in Potter County along about 1937. (Vol. XCIX, pp. 15307, 15308.). The witness stated that he had made a particular study as to the general accumulated per-acre withdrawals averaged over the areas included in various pressure bands and this showed conclusively that the extension of the low pressure area in pressures of less than 400 pounds which had extended into Potter and southern Moore Counties over a period of years resulted primarily from drainage of gas out of Potter and southern Moore Counties rather than from withdrawals of gas out of wells located within those areas. The general extension of low pressure contours in a southwesterly direction outward from the Borger-Sanford area has resulted primarily from drainage of gas out of Potter and Moore Counties rather than from withdrawals of gas out of wells located within those areas. The general extension of low pressure contours—in a southwesterly direction outward from the Borger-Sanford area has resulted primarily from drainage of gas out of Potter and Moore Counties toward the lower pressure areas. (Vol. XCIX, pp. 15310-15312.)

The witness further stated that the pressure decline of practically every well lying in southeastern Moore County and in southwestern Hutchinson County has been influenced by drainage of gas out of Potter County acreage. This does not mean that a cubic foot of gas that originally lay in Potter County has moved on over and come out of a well in the Sanford area. It does mean that gas which was originally close to that well in the Sanford area has been moved toward the well by expansion which carried back from pressure band to pressure band and which ties into expansion of gas over into Potter County and drainage of gas out of Potter County. (Vol. XCIX, pp. 15314, 15315.) It is obvious that gas is draining into the Sanford area as reflected by the increase in pressures of many wells in that area since 1935. (Vol. XCIX, pp. 15316, 15317.)

The witness was then asked if it was not true that if there was any drainage out of Canadian acreage it would be out of that portion of its acreage located in the southwestern part of Hutchinson County. The witness replied that there

undoubtedly was drainage out of such acreage but at the same time the acreage was receiving extensive replenishment of gas as a result of drainage from the southwest, and it was losing gas extensively to the northeast. Canadian leases in southwestern Hutchinson County show a general decline in pressure. The replenishment from the southwest has been less in total effect than the combined effect of production and drainage loss, and therefore, there has been a decline in pressure. The fact that the pressure band from 300 to 350 pounds in southwestern Hutchinson County has moved slowly to the southwest indicates that the combined effect of drainage of gas out of that area and the production of gas out of wells in that area slightly exceeded the replenishment that that area had received by drainage into it from the southwest. (Vol. XCIX, pp. 15320, 15321, 15324.) The witness does not have the exact figures as to the production by Canadian from its leases in southwestern Hutchinson County, although he does know the approximate volume that has been produced. Witness did state, however, that the average per-acre withdrawals in that area had been less than the average per-acre withdrawals in the immediate adjacent sour gas area. (Vol. XCIX, p. 15321.)

Testimony of the Various Witnesses Relating to the Life of Canadian's Reserves.

Stanley Gill has testified at length on this question, which testimony has been heretofore abstracted. During the course of his testimony on the subject, generally, he stated the following:

> "It seems * * * very reasonable to assume that the economic life of Canadian River Gas Company's reserves will be determined by the economic life of the Texas Panhandle Field as a whole." (Vol. XCI, p. 14047, Exhibit 266, p. 13.)

Thompson testified that the life of Canadian's reserves as a practical matter is the same as the life of the Texas Panhandle Field as a whole. (Vol. XCIV, p. 14387.)

Hughes testified that the life of Canadian's gas reserves was about the same as the life of the field as a whole for the production of natural gas for long distance pipe lines. (Vol. XCV, pp. 14638-14639.)

Massa testified that the life of the field as a whole and the life of Canadian's reserves are the same. (Vol. LXXXIX, p. 13551.)

Peterson did not testify specifically on this point but did testify generally that:

> "The life of each lease must depend upon the life of the field." (Vol. LXXXII, p. 12229.)

Dickinson, witness for the Commission, testified generally that the life of Canadian's reserves was about twelve years from January 1, 1940, and that his company, which gets a portion of its gas from Canadian's acreage, considered that there would be no more pipe line property in service by the end of 1952. (Vol. LXIV, p. 9232.)

Additional Testimony With Respect To Canadian Acreage.

MAX K. WATSON, witness for Canadian, also testified on cross examination (Vol. 21, pp. 2968-2974; 2979-2980; 2990-3004; 3013-3018) as follows:

Q. Now, on Page 2, right below that listing of wells for each year you have this statement:

"With the exception of five so-called exploratory wells involved in lease obligations, the above drilling program contemplates that the wells to be drilled * * *" and so forth.

What five so-called exploratory wells do you have in mind?

A. This one well on the City of Amarillo section called the City of Amarillo test No. 1 and four wells to be drilled on the Bivins Consolidated lease, according to the contracts.

Q. Now, then, those five are included in this total of 41?

A. Yes, sir.

Q. Now, one has been drilled and that is the dry hole that you referred to, the City of Amarillo?

A. Yes, sir.

Q. Now, is any one of these remaining four so-called exploratory wells involved in your 1941 figure of five wells?

A. 1941 estimate?

Q. Yes.

A. Yes, there is one well included in 1941.

Q. Now, under what lease or leases are these five so-called exploratory wells set forth or where are the obligations to drill those wells set forth?

A. The four exploratory wells in the Bivins Consolidated lease.

Q. Four of them?

A. And one in the acreage acquired from the City of Amarillo.

Q. All right, one is already drilled. Now where in the Bivins Consolidated lease acreage are these exploratory wells to be drilled that you say are obligations under that lease?

A. We are to designate, as I recall it, the blocks of acreage. I'm afraid I can't answer that question. I am trying to say it from memory and we better refer to the lease.

Q. Those provisions are set forth in the lease, in the Bivins Consolidated lease?

A. Yes, sir.

Q. And do you have any independent knowledge of where that acreage is located with reference to the other acreage of Canadian River Gas Company?

A. In general?

Q. Yes, the acreage on which these exploratory wells are to be drilled.

A. They are south of that white line we called "Fault Line."

Q. In other words, south of the "Fault Line" on this exhibit 13-A, aren't they?

A. Generally south of there. Now, I don't know whether that is the same line to which I am thinking or not, but if that is our fault line they are south of it.

Q. All right, what does this fault line indicate on this map?

A. It indicates the probable limits of production with the information we have available today.

Q. Probable limits of production and that production has been north and east of the fault line, hasn't it?

A. Yes, sir.

Q. But this group of wells termed "Exploratory Wells" would be drilled south of that fault line?

A. I believe in every instance they would be drilled south of our fault line, as established by our own engineers.

Q. South of the boundary of the field?

A. That established by our own engineers.

Q. Yes. Well, is there any production in that area south of that fault line?

A. Yes, sir.

Q. Gas?

A. Yes, sir.

Q. In the Bivins lease?

A. Yes, sir.

Q. In this lease under which you are proposing to drill these exploratory wells?

A. Not in the consolidated lease, no.

Q. Not in the consolidated lease?

A. No, sir.

Q. And you are drilling these so-called exploratory wells specifically under drilling obligations, is that the reason you have them set forth?

A. As I remember it, they are specifically required.

Q. You wouldn't drill them down there if you didn't have a drilling obligation?

A. Well, possibly. When—

Q. You mean you would drill them in the area south of the fault line on this lease with the view of obtaining gas if you had no drilling obligation to do it?

A. Well, there may be gas down there.

Q. Has the company drilled any wells down there excepting these that they propose to drill under, as you say, a drilling operation?

A. The one City of Amarillo test.

Q. Is that in the Bivins field?

A. No, sir; it is in the area.

Q. I am talking about this great big block of acreage under this Bivins Consolidated lease that you would call the exploratory well area, whether the company has drilled any wells in that area itself before this.

A. Yes, sir.

Q. When?

A. 1928 or 1929.

Q. That is right. What did it find? How did the wells turn out?

A. Gas wells.

Q. Where are they located?

A. In the helium structure—the Cliffside structure.

Q. The Cliffside structure?

A. Yes, sir.

Q. I still say that it isn't within the acreage upon which you propose to drill the exploratory wells.

A. I don't know. We won't know until we drill.

Q. You don't mean to say the Cliffside structure is included in the Bivins Consolidated lease at present?

A. Maybe there are some sections in it. I don't know.

Q. Do you know exactly where these groups of acreages are upon which these exploratory wells are to be drilled?

A. It is fairly well scattered from Amarillo north clear into our present block of proven acreage.

Q. You yourself said the fault line is the line indicated on that map as representing the outline of the field, the proven field, didn't you?

A. I said as defined by present information.

Q. That is right. That is what we are going by. This is your company's map.

The so-called exploratory wells that you are proposing to drill and you have in this drilling program are being drilled to comply with the drilling obligations under the Bivins Consolidated lease?

A. They may also be to prove the information available today.

Q. Is that why you gave instructions to put in it this list, or did you put it in here to have them here involved in drilling obligation?

A. I put them in this list because the lease says specifically that they have to be here.

Q. Why do you make this statement—in other words, that is the only reason you put them in this lease, because the lease obligation requires you to drill them?

A. That isn't the reason I put them in here.

Q. That is the only reason you based the drilling on?

A. The only reason I based this drilling personally.

Q. You *way* that with the exception of five so-called exploratory wells involved in lease obligation, the above drilling program contemplates that the wells to be drilled will be completed as wells capable of producing gas in average quantities. In other words, in that statement you

are proposing to drill the other wells with a view of getting gas but you don't have such hopes with these exploratory wells?

A. It isn't very probable.

Q. It isn't very probable that you would get gas?

A. I don't know. You might say that that is a layman's opinion; not being a geologist, I don't know.

* * * * *

Q. And the Cliffside structure is not in this acreage upon which you are going to drill the exploratory well?

A. It is not in there, no.

Q. Where is it located with reference to this acreage upon which you are going to drill these exploratory wells, the Cliffside structure in relation to this acreage?

A. It is possibly—some of this acreage in the Consolidated Bivins lease may be in close proximity if not on the Cliffside structure.

Q. From your lease records you can certainly determine whether the Cliffside structure is separate or is a part of this acreage on which you are going to drill these exploratory wells, can't you?

A. I don't think the Cliffside structure is defined by the Government—that any of the acreage on the Cliffside structure is defined by the Government as included in this Bivins Consolidated lease because the Government had already purchased all the land which they thought at that time was in the Cliffside structure, but it is possible some of the acreage lies close to the Cliffside structure.

Q. Let me ask you this: Is there any producing gas well in this acreage in the Bivins lease that is set aside for these exploratory wells?

A. No, there is no gas produced from any of the acreage which is set aside for these exploratory wells.

* * * * *

Q. Now, then, this acreage on which these exploratory wells would be drilled, the first well in that group, is that reflected on this map?

A. The first well drilled when?

Q. To be drilled on that exploratory program.

A. It is somewhere on that exploratory lease.

Q. Where would that be located?

A. It isn't designated yet.

Q. Aren't those tracts set out as to each year, the num-

ber of acres in each tract, and then you determine where the well is to be drilled during that year?

A. I don't recall. As I understand it, the tracts are designated just before they are drilled, however, it may be those tracts have been designated and the map not definitely located on those tracts.

Q. I see. Now, that first well that was drilled on that exploratory program that you mentioned this morning—I want to come back to that. Where was that drilled, the well that resulted in a dry hole?

A. We have drilled two exploratory wells, you might say, since we acquired the Consolidated Bivins lease.

Q. The last one that resulted in a dry hole, what section was that drilled in?

A. In the Bivins exploratory lease?

Q. Yes.

A. The only one drilled was in Section 49, D & P Railroad, Block 018.

Q. That is colored yellow on the map?

A. Yes, sir.

Q. Now, then—

A. That well was drilled in 1939.

Q. 1939?

A. Yes.

Q. What did that well cost?

A. I don't have any figure on that.

Q. You don't have any figure on that?

A. No.

Q. Was the drilling of it contracted out or did your company drill it?

A. It was drilled the same as all the other wells have been drilled in the last several years.

Q. By the Phoenix Drilling Company?

A. Yes.

Q. And to what depth did they drill?

A. Possibly I have that information here. (Examining documents.) Yes, here it is.

Do you want the definite location on that?

Q. Yes.

A. Bivins A-26 was located 2,640 feet from the west line, 3,068 feet from the south line, Section 49, Block 018, D & P

Railroad Company survey, Potter County, Texas. The drilling was completed December 16, 1939. It was drilled to a total depth of 3,547 feet.

Q. No production at all was shown from that well?

A. No gas production, no, sir.

Q. Was there any oil production?

A. No, sir. It had a lot of salt water production, though.

Q. And you will get the cost of that well?

A. Yes, we can get that.

Q. All right. After that was drilled, isn't it a fact that the company, instead of drilling on a second block of that acreage, exercised its option and released the whole acreage, that whole block, rather than drill on the acreage?

A. I believe they did but I don't think I would know that definitely.

Q. You don't know whether on April 27, 1940 they exercised the option not to drill on the second block of that acreage and released it back to the lessor under the lease agreement?

A. I recall discussing that with Mr. Ford but I have never seen correspondence or a release on that.

Mr. Lange: We have a copy. It is not certified, but we would like to file it. We will have to make copies of it for counsel, it being subject to check for accuracy.

(The document referred to was passed to counsel.)

Mr. Keffer: We have no objection to the instrument being offered, if Mr. Lange desires to offer it, with the reservation, however, that we will have an opportunity to check it as to accuracy.

Mr. Lange: Oh, yes. It will be subject to check for accuracy.

The Trial Examiner: Now, Mr. Lange, I don't believe you stated exactly what the document was.

Mr. Lange: While the instrument doesn't bear any particular label, it purports to be a release of a certain block of acreage under the Bivins Consolidated lease, purportedly under provisions of that lease which are referred to in the instrument.

The Trial Examiner: What was the date of that instrument, Mr. Lange?

Mr. Lange: It is executed by Canadian River Gas Company, R. E. Wertz, Vice President, bearing the company's seal, and it is attested to by the Secretary, bearing date of April 27, 1940. We will have copies of it made in order to supply them to counsel.

The Trial Examiner: Very well. It will be marked for identification as Exhibit No. 96.

(Exhibit 96, Witness Watson, marked for identification.)

The Trial Examiner: I understand that you offer it in evidence, do you not?

Mr. Lange: Yes, sir.

The Trial Examiner: You have no objection to it being received in evidence subject to the provision you stated?

Mr. Keffer: That is right.

The Trial Examiner: Exhibit No. 96 will be received in evidence.

(Exhibit 96, Witness Watson, received in evidence.)

By Mr. Lange:

Q. Mr. Watson, do you know of the execution of that release of a block of this exploratory acreage on the Bivins lease?

A. No, sir, I have never seen it before.

Q. Will you read it and check it for accuracy in so far as you are informed as to the acreage involved?

A. I couldn't check it by just reading it, no.

Q. This is, as you have heard, a release of a certain acreage executed by Canadian River Company, It includes in that release designated acreage totaling 10,102.70 acres and gives that acreage by sections, and wherever it is only a portion of a section it so indicates.

Now, then, from that description could you point out on this map where the acreage is situated?

A. Yes, from that description I can pick it out on the map.

Q. Now, with reference to the Bivins lease indicated in yellow on this map, can you mark with an X mark those sections that are included in that release?

A. I expect I can find them.

Q. All right. Read each one when you check it so the reporter can get it down. If it is only a part of the section, so indicate.

A. This is designated as Drilling Block No. 1 in the so-called Bivins Consolidated lease. Section 17, the west-half and south quarter of Hartley County, 480 acres—this is going to take me some time.

Q. Well, I can read them off to you and you can locate them on the map. Will that speed it up?

A. I might as well have the data in my hands. To locate these sections as they are spread out on the map, I am going to have to check and double-check it. It is no simple job to check the sections.

Q. Where are they located generally?

A. This is a definite location or section which I will have to put a cross through.

Q. Very well, mark each one as you locate it.

The Trial Examiner: Are you putting a cross in there to signify the section?

Mr. Lange: He is putting an X mark in there to signify the section included in the release.

The Witness: I just mentioned this section which I will designate on the map now by an X mark.

Section 18, north 480 acres in Hartley County. The heading of this list of acreage should have been designated as Capital State Syndicate Survey, Block No. 21.

Q. All right.

A. It is designated on this map as B21-CSS.

Section 19, portion, all; located in Hartley County, 640 acres.

Section 29, portion, all; located in Hartley County, 365.7 acres.

Section 30, portion, all; located in Hartley County, 608 acres.

In the Capital State Syndicate Survey, Block No. 20, the following sections or portions of sections:

Section 26, portion, all; located in Hartley County and Oldham *Counties*, 597.6 acres.

Section 27, portion, all; Hartley and Oldham Counties, 640 acres.

Section 25, portion, all; in Oldham County, 234.4 acres.

Section 24, portion, all; located in Oldham County, 640 acres.

The next heading is Gunter & Munson, Block No. 2.

The Trial Examiner: How do you spell the first name?

The Witness: Gunter, G-u-n-t-e-r.

Did I read that for Section 24, portions all, in Oldham County, 473 acres? (No response.)

Section 23, portion, all; in Oldham County, 640 acres.

Section 67, portion, all; in Oldham County, 657 acres.

Section 27, portion, all; Oldham County, 322 acres.

Section 26, portion, all; in Oldham County, 325 acres.

Section 68, portion, all; Oldham County, 755 acres.

Section 64, portion, all; Oldham County, 640 acres.

Section 65, portion, all; Oldham County, 6440 acres.

The next group is East Line and Red River Railroad Survey, Block 9.

Section 1, portion, all; in Oldham County, 320 acres.

Section 2, portion, all; Oldham County, 320 acres.

That concludes this list, subject, of course, to correction.

Q. That is the total acreage indicated on this instrument, this release of approximately 10,102.70 acres?

A. Yes, sir, according to this instrument.

Q. Now, then, this block of acreage of 10,102.70 acres was released by the company in the exercise of its option under the Bivins lease not to drill that well, but, rather, to release this acreage and eliminate it from the lease?

A. According to that instrument, that is correct.

Q. So, under that the company would not have to—strike that.

In view of this release, the company did not have to drill that well and spend the amount of money that you had indicated as a minimum amounting to $30,000 per well that would have to be spent for the drilling of that well?

A. According to that instrument, that is correct.

Q. The only other well they drilled under these exploratory provisions resulted in a dry hole?

A. That is correct.

Q. Now, then, as I understand it, the company has the privilege under the Bivins Consolidated lease to release a similar block of acreage each year rather than drill and expend that amount of money in a minimum of at least $30,000? They could do that, couldn't they?

A. (Pause.)

Q. They could release the acreage rather than spend the money for the drilling of the well, couldn't they?

A. I believe that instrument states that.

Q. And if that is correct, the provision of the lease provided that that could be done with reference to these remaining four wells that you included in your drilling program, couldn't it?

A. Not according to that instrument. That covers only one 10,000-acre block.

Q. It covers only one 10,000-acre block?

A. Yes.

Q. But the company could proceed in like fashion for each of those four years if they desired?

A. I do not know whether that is right or not.

Q. You don't know?

A. No.

Q. You wouldn't say they could not do it?

A. No.

Q. It depends upon how long the lease reads?

A. That is right.

Q. You do know they did it in this one instance?

A. Yes, sir.

Q. And if they had the privilege to do it under the lease in this one instance and would exercise such an option each year, it would obviate the drilling of four wells out of their 1941 well program?

A. It would eliminate the exploratory wells.

Q. Yes, or a total minimum cost estimated by you as $120,000, being $30,000 per well?

A. That is correct.

Q. I notice this block of acreage that was included in this lease was all lying south of the fault line. Isn't that correct?

A. Yes, sir.

Q. You haven't had the opportunity to determine the accuracy of the map with reference to the several leases reflected thereon; however, all of this group of acreage which you said was designated in that release is in the portion shaded yellow, isn't it?

A. All that I have marked on the map as designated in that instrument, Exhibit No. 96, was.

Q. Yes.

A. It was in the territory colored yellow on the map.

Q. The legend on the map recites that the acreage colored yellow is the Bivins acreage embracing a total of 167,994.94 acres?

A. The legend on this map shows the same color as far as I can tell, designated yellow on the map; designation, number 30; lease named, Bivins; acreage, 167,994.94; per cent, 51.69.

Q. And this lease of some 10,000 acres comes out of that total acreage?

A. I don't know what it comes out of.

Q. The release cites it as out of Bivins acreage?

A. That is correct. It comes out of the Bivins consolidated acreage. As to whether it is that figure or not, I do not know.

Q. This figure in the legend is subject to correction as to accuracy and you are not substantiating that at this time.

Now, then, I notice this map carries the descriptive matter, as far as acreage and geographical locations are concerned, down to the City of Amarillo. This morning we were not able to spot-check the exact location of that dry hole drilled by your company in the vicinity of Amarillo. Can you do that now, Mr. Watson?

A. If I refer to my working papers to find the definite location of it, I can. (Examining document.) 167, 1980 feet

from the east line; 2640 feet from the south line of Section 167, Block 2, A. B. & M. Survey, Potter County, Texas.

The Trial Examiner: How did you designate it there? with a circle?

The Witness: With a circle.

By Mr. Lange:

Q. Now, that section isn't colored, is it, Mr. Watson?
A. No, sir. On this map it is not colored.
Q. It is not colored on this map. Now, it is joining a section that is colored yellow?
A. That's correct.
Q. That is Section 190?
A. Section 190.
Q. Then there is some other yellow sections, aren't there?
A. Yes.
Q. In that group. What are the others that are contiguous to the 190 that are colored yellow?
A. There is 480 acres out of Section 223; 480 acres out of Section 191.
Q. All of those that join the yellow group?
A. Section 192—full section 192; two-quarters of Section 221; two-quarters of Section 193. All of those are sections joining the section in which the City of Amarillo well was drilled, or joining each other.
Q. You haven't drilled on any of those sections, have you?
A. We have not.
Q. Any of those yellow sections that you just named.
A. We have drilled no wells on any of those yellow sections just named.
Q. And you stated this morning on request that you would get the copy of the lease on that section that you drilled the dry hole. You said you didn't have it but would get it.
A. A copy of the lease on Section 167?
Q. Yes.
A. Yes, sir.
Q. As well as the assignment of any part of the acreage.
A. We can get that.
Q. Now, do you have any information on which you can block this acreage in the Bivins lease on which these exploratory—on which the next exploratory well is to be drilled?

A. No.

Q. Well, could you block all of the acreage on which this group of four exploratory wells would be drilled regardless of their location?

A. Not from the information I have at present with me.

Q. Well, you have it available, don't you?

A. I expect it will be included in that Bivins Consolidated lease.

Q. From which you could block all of the acreage included in this area where the four exploratory wells would be drilled?

A. If those areas you designate are in that Consolidated lease, then I could tell in general where those wells would be drilled, but not the year in which each individual well would be drilled in each specific block.

Q. That's right, but you could mark an X on each of the blocks just as you did on the—as it has now been marked. Given those sections, why, you can mark all of those on the map?

A. All of those included in the exploratory lease.

Q. That's right.

* * * * *

Q. Now let's go to 1942. You have got six wells planned for that year?

A. Yes, sir.

Q. One of which is this exploratory well and in connection with that as with the exploratory well for 1941, if the provisions of the lease of the Bivins Consolidated are such that the company may exercise an option to release that block of acreage in lieu of incurring drilling obligations, why, that would eliminate one of those wells, wouldn't it, in 1942? If that is correct?

A. I don't know what that would be. This is my schedule.

Q. But I say, if the company has that option and exercises it like it did under this block under which they got a release, then there would be one well less in that program?

A. Then they would instruct me not to drill that exploratory well.

Q. Then that would leave five wells for 1942.

A. That is correct.

Q. Now, then, what is the first of those five wells? Where is it going to be and why is it going to be drilled?

A. Two wells will be drilled on a Bivins Consolidated lease for the same reasons for those drilled in prior years.

Q. Under this provision (b), to satisfy obligations under the lease?

A. As the period which we have estimated our development program to cover, as that period progresses the wells that we will drill will also begin to come under the requirements of our peak day, average peak month demands, that we will need that gas for other than such lease requirements.

Q. All right, let's see the first well that you are going to need. Is 1942 going to get into that part of the picture as to additional well requirements or additional amounts of gas to meet peak requirements?

A. It is going to be most difficult for me to say in what year any one well might be required for that purpose. I have looked at this program over the period from 1940 to 1947 and I have considered only average conditions, the probabilities, and although I have designated the well each year, it was for the purpose of only developing an early program, as being more economical and more practical from an operating point of view. Now, as to whether I drill a well in 1942 to supply my peak day will be most difficult to determine.

Q. All right, then, assuming that when you get to 1942 you are going to begin needing such a situation where peak days are going to require additional gas and therefore you have reached the conclusion that then you will have to drill another well.

A. No, I would believe that in 1942 we probably wouldn't need either of those wells for a peak day, but, however, a prudent operator would never drill right up to only his requirements. He would have a certain leeway, as explained this morning, for emergencies which the hazards of the business always force you to face one day or another.

Q. Well, how have you arrived at any even remote conclusion that by 1942 your peak days are going to require the gas that you could produce from an additional well?

A. Well, we'll refer to my Exhibit No. 94, Page 2, the middle of the paragraph, middle of the page:

"In arranging the program, the period covered has been considered as a whole and the total number of wells required has been to some extent apportioned over the years covered.

in order to avoid an abnormally large drilling program in any one year and to obtain the benefit of the knowledge gained from drilling a few wells for the purpose of most advantageously locating subsequent wells."

Q. Is that the basis on which you are proceeding in your drilling program for 1942?

A. Yes, sir.

Q. All right, now, aside from this lease obligation that you refer to, just tell us by what method you arrive at this conclusion that you are going to require this additional gas that will be produced from that well in order to take care of your peak days.

A. I figured my requirements in 1947, the number of wells I would require between the date of 1940 to 1947 and I distributed the drilling of those wells as uniformly as possible over the period covered from 1940 to 1947. Therefore, my requirements were estimated over the total period, as for any lease.

Q. All right, what are the mechanics that you went about in estimating those requirements?

A. We used the official Railway Commission tests as obtained in July and August of 1940 as to the potential of the wells on that date, on the date of which it was tested and the same curve would indicate the potential of any well at any other rock pressure. Now, that is as to the wells that are now drilled. I have the definite back pressure curve as obtained from the Railway Commission tests on the dates indicated.

Q. You have plotted that curve?

A. Yes, sir.

Q. Do you have a copy of it?

A. Yes, sir.

Q. Can we have it?

A. That curve?

Q. Yes.

A. They are in my work sheets and all bound together—quite a little book of it.

The Trial Examiner: We will stand in recess for five minutes.

(At this point a short recess was taken, after which proceedings were resumed as follows:)

The Trial Examiner: The hearing will be in order.

By Mr. Lange:

Q. What does this represent, Mr. Watson, this document?

A. They are sheets or curves plotted on log log paper in the back of this book which represents the test on each individual well as conducted jointly by the Railway Commission and the Canadian River Gas Company.

The Trial Examiner: The Railway Commission of Texas?

The Witness: The Railway Commission of Texas and the Canadian River Gas Company.

By Mr. Lange:

Q. How did you arrive at the construction of the average curve that you have on the first page?

A. The average curve—this book also contains a curve which I have designated as an average back pressure test, sweet and sour wells, from Railway Commission tests in 1940. That curve represents an average of all of the tests included as to each well in this same book.

Q. Now, how did you arrive at the rock pressure tests that you have for the year 1947?

A. I would like to read from my exhibit which is explicit, Page 3, the paragraph in the middle of the page:

"The future drilling program outlined above is based upon an average rock pressure decline of approximately 100 pounds during the period estimated, within the general area in which future wells of the company will be drilled. This is a judgment figure based upon my observation of the past performance of gas wells of the company as well as other gas wells in the field; also upon my knowledge of general conditions prevailing in the field."

Max K. Watson further testified on cross examination (Vol. 22, pp. 3055-3057; 3058; 3065-3070; 3081; 3100-3102) as follows:

Q. Now, referring to this Exhibit 94, Page 3, the center of the page, you make this statement:

"The future drilling program outlined above is based upon an average rock-pressure decline of approximately 100 pounds during the period estimated."

That is a period from what time to what time?

A. From 1940 to 1947.

Q. The period estimated?

Mr. Keffer: Are those years inclusive?

The Witness: Those years are inclusive.

By Mr. Lange:

Q. Then you continue on:

"* * * within the general area in which future wells of the company will be drilled. This is a judgment figure based upon my observation of the past performance of gas wells of the company as well as other gas wells in the field; also upon my knowledge of general conditions prevailing in the field."

Now, then, in arriving at this so-called judgment figure, what relation did you make to this so-called 100 per cent drop in pressure?

A. 100 per cent?

Q. 100 pound figure. I beg your pardon—drop in pressure.

A. I referred to the performance of the whole field, the trend within our own block of acreage and specific wells, the history of specific wells within our acreage, the history of specific wells throughout the Panhandle field.

Q. Well, did you consider the amount of past production of your company's wells, let's say during the past three years?

A. No, sir. That had no bearing at all on what I was studying.

Q. It had no bearing at all?

A. No, sir.

Q. The past production from your wells?

A. I was taking the trend of rock-pressure decline. As to its cause, I didn't investigate.

* * * * *

A. We possibly will not have rock pressures on all wells in any one month in any one year because they couldn't be shut in for sufficient time—

* * * * *

Q. You are still of the opinion that the judgment figure that you have used on Page 3 is better than just confining yourself to the company's actual past history?

A. Yes, sir.

Q. Why?

A. For this reason: We had not suffered appreciable drainage prior to about 1938. If you will look at your rock-pressure map of the Panhandle field, our acreage is the only one with the exception of a smaller part of the Cities Service in which there is practically—not practically, but close to virgin rock pressure, so it is obvious that somebody must supply the gas that has already been withdrawn from the field. Since the pressure is higher on our acreage than where it is being produced, we are going to suffer increased rate of migration.

Q. With reference to—

A. Therefore, the rock pressure would decline at a faster rate than increasing increment.

Q. Has there been any increases in rock pressures in any of your wells?

A. There has been an increase in indicated rock pressure but any individual rock pressure is subject to errors of the observer, for one thing, and another is that the well may have been pulled continually at a high rate and had not recovered its rock pressure. If you take any specific date on any specific well and pay no attention to the trends of before and after, there you will find it will be misleading because a well cannot have an increase in rock pressure as rock pressure when there are withdrawals continuing in the field.

Q. How do you account for that showing of an increase when there is such a showing?

A. As I explained, the first might be that a person, a man observes that pressure and reads it as he sees it. Of course, he is reading a pressure gauge or dead-weight gauge and he might misread it and not knowing he has misread it report it to the office. We record that pressure because it has an observation. He may have read it right.

The next observation, if it shows an increase, shows that pressure was not rock pressure but some other pressure and it may have been a partial rock pressure or an error in observation. Therefore, a specific rock pressure taken by itself may be a normal increase or an abnormal decrease, but

the trend is if enough pressures are taken you have eliminated the possibility of the things I have just mentioned.

Q. Just as you mentioned, too, there may be that same character of error reflected in a reading that shows a decrease of pressure?

A. Yes. It is the same way unless the decrease continues for subsequent and prior rock-pressure recordings. If it is a consistent decline, you can check that pressure as being correct because you don't make the same error each time you read it.

Q. In your experience, how frequently or how common are such errors in the reading of the pressures?

A. I don't believe a man would make the same error twice for the reason that if we see an abnormal pressure, either high or low, we call it to the tester's attention. When he goes back to the well he is as much interested as we are in getting the right answer. He would be careful in taking the pressures as of that date and the well would be left shut in if it did not increase in pressure any more, if it was possible to do so, and the next pressure would be; more than likely the correct pressure, although still the error might be there as to the length of time shut in.

Here is what I am trying to point out: If I go to a well on January 1, 1940 and I get 390 pounds; then I go there in March and get 400 pounds, and I go there in June and I get 400 pounds; I go there in July and I get 398 pounds, and I go there later in the year and get 397 pounds—I never did observe a pressure less than 390 pounds—I naturally could eliminate 390 pounds because the trend was from 400 pounds down, indicating that the 390 pounds should have been 400 or 401 pounds, and the other pressures, because they showed the trend carried on throughout the subsequent observation period was declining, which it should do. There can be no reason for a well increasing in pressure unless the production around that well or in that area has decreased or you might say ceased. That has been the case in the Borger area, but they were withdrawing a normal amount of gas and it was migrating in. When the distributing law was passed the field was shut in and the heavy withdrawals were discontinued. Then the pressures began to build up. We have one well which I am satisfied the pressure has built

up two or three pounds over a period of a year. It was over in that heavy withdrawal area.

Q. Which well is that?

A. Bivins B-5.

Q. Bivins B-5?

A. Yes.

Q. And how did that behave?

A. It builds up, as I recall it, two or three pounds after the shut-down order was made and stripping was stopped it built up a few pounds because it was close to heavy withdrawals. Naturally, the withdrawals were holding that pressure down and as soon as it shut down the pressure built up. It built up possibly for a year or two and the natural decline took effect again as it started down and has continued down.

Q. Do you have any other well that behaves in a similar fashion?

A. That builds up?

Q. Yes.

A. A continuous buildup over a period of time that I would be willing to accept as a buildup?

Q. Yes.

A. I don't believe there was. Possibly our Bivins B-2, the closest to the Bivins B-5, may have built up or the rate of decline may have decreased but I am not certain of that. It is an area in there that was suffering excessive drainage.

Q. How do you know that it was suffering excessive drainage?

A. From the rapid decline of rock pressure.

Q. You relate that directly to the rapid decline of rock pressure as indicated in those wells?

A. I don't necessarily, but it certainly indicates the rapid decline and certainly indicates rapid withdrawals and we weren't withdrawing it at any rapid rate so it must have been migrating out of that area.

Q. Well, why has there been no drilling on those leases and the company continues to hold them anyway?

A. Because drilling wasn't required.

Q. And those leases, then, don't get any protection under the company's equitable prorations program?

A. I presume they are protected by some other means other than including them in the proration picture.

* * * * *

Q. Now, then, in any of these proposed wells you have set forth on this list on Page 2, eliminating those so-called exploratory wells, would any of those wells in the remaining list be drilled in the sweet gas area, all of them in the sweet gas area?

A. All of them would be drilled in the sweet gas area.

Q. They would?

A. Yes.

Q. Now, then, on Page 8 of Exhibit No. 94 you have this provision: "Sour Gas Treating Plant"—before I get to that I wish to ask you this: Does the company have no producing wells at present that have sufficient—strike that "sufficient"—that have a volume of gas—no, that have a quantity of sour gas sufficient to keep them off the line?

A. We can produce from those sour gas wells a small quantity of gas which will not contaminate the total amount of gas pressure so it will not be usable for pipe line use, so if all of the wells with the exception of one are producing small quantities of gas—

Q. Into the line at present?

A. Very small quantities to the line at present.

Q. Can you spot those wells on the map?

A. Yes, sir.

Q. Will you do so?

A. Bivins A-9, located in Section 6, C & S S, Block 21; Bivins A-10, Section 18, G & M, Block 2; A-8, Section 4, E L & R R R R, Block 25; Bivins A-22, Section 13, G & M, Block 2, which is not connected. Those locations, especially the block numbers, are subject to correction.

Q. Yes. That is the total of how many wells that produce sour gas?

A. Four wells.

Q. What is the percentage? Have they been tested with reference to the quantity of sour gas?

A. Yes.

Q. What do they show?

A. Varying quantities. Beginning with the well closest to the sour line it is a little less than two grains as determined by the Texas Railroad Commission, and getting progressively more sour west to, as I recall it, it is approximately 9 grains or 12 grains, on Bivins A-9 as tested by the Canadian River Gas Company. The Railroad Commission was only interested in locating the sour gas line and they

assumed that all wells west of that line were sour and did not test them, and such is the case.

Q. What are the open flows of those wells, the last that you have record of?

MAX K. WATSON further testified on cross examination (Vol. 30, pp. 4156-4159) as follows:

Q. Now, Mr. Watson, the company proceeded with the drilling and actually completed the drilling of that Amarillo No. 1, didn't they?

A. Yes, sir.

Q. And what was the approximate total cost of that well?

A. Approximately $49,000.

Q. Approximately $49,000?

A. Yes.

Q. And just so that it ties right in at that point—it may be in the record heretofore—what was the approximate time that that well was completed? What month and year?

A. Early in 1940.

Q. Early in 1940. Do you recall the month?

A. No. I can find that in the record here somewhere. The City of Amarillo No. 1, completed June 17, 1940.

Q. Completed June 17, 1940?

A. Yes, sir.

Q. Now, then, if that well had been brought in as a producing gas well—strike that.

Are there any producing gas wells right in that locality on any of that acreage in that locality?

A. The Helium structure produces about ten miles northwest of that location.

Q. Not any gas producing well is in existence on any of the yellow Bivins blocks on this map, Exhibit No. 95, is there?

A. No, sir.

Q. And you stated that the company had not heretofore drilled any of those blocks on the Bivins acreage?

A. Oh, yes.

Q. Contiguous to the acreage on which this Amarillo No. 1 was drilled?

A. That block to which you are referring on that Bivins consolidated lease—

Q. Yes.

A. —is not all contiguous to that City of Amarillo test. That block is spread out all over Potter County.

Q. But the block itself, all of which is contiguous to one block of Bivins acreage—

A. Some of the acreage is contiguous to the City of Amarillo test but not all of it.

Q. That's right, but not on any one of those sections in that yellow acreage designated on the map, Exhibit No. 95, contiguous to or adjoining the acreage on which Amarillo No. 1 was drilled has heretofore been drilled by Canadian River Gas Company?

A. No. There are only two thousand acres of that block contiguous. The other eight thousand acres is somewhere else.

Q. I see, but I want to get definitely fixed that there is no well drilled by Canadian River Gas Company as a test on any of this Bivins acreage contiguous to Amarillo—

The Trial Examiner: What is that section number, Mr. Lange?

Mr. Lange: Section 190.

Q. Now, then, if this well Amarillo No. 1 had been brought in as a producing gas well, where would delivery of that gas have been made?

A. Probably would have been made on the Amarillo Oil Company lines supplying Amarillo with gas, if there had been a gas well.

Q. If it had been an oil well, according to this Exhibit 123, the Amarillo Oil Company having retained the oil rights, what would have happened to the well?

A. I don't know. I suppose the Amarillo Oil Company would have had an oil well.

Q. You don't know under what arrangements that would have been handled?

A. No, sir.

Mr. Keffer: Right in that connection, Mr. Lange, I believe the agreement shows precisely how it would have been handled.

Mr. Lange: I was asking whether this witness knew of his own knowledge.

We will prepare the necessary copies of the three exhibits 122, 123 and 124, Mr. Examiner, and make them available.

Exhibit 123 introduced by Commission constitutes the agreement between Amarillo Oil Company and Canadian River Gas Company with respect to the well drilled by Canadian River Gas Company on land owned by the City of Amarillo, and which was drilled near the city limits of Amarillo. Said Exhibit provides that Amarillo Oil Company should assign to Canadian the gas rights on oil and gas leases aggregating in excess of 4,000 acres, including three tracts that Amarillo Oil Company had contracted for but had not at that time acquired title.

The contract among other things provides:

"Amarillo Oil Company will assign the leases listed above and such leases as it acquires under the contracts mentioned above, to Canadian River Gas Company on the following terms and conditions:

"A. Amarillo Oil Company will assume the entire cost of acquiring such leases and contracts for leases;

"B. Amarillo Oil Company will retain the oil and oil rights;

"C. Canadian River Gas Company will assume the obligation as to the drilling of the test well as provided for in the proposed lease from City of Amarillo to Amarillo Oil Company, covered by the agreement with the City of Amarillo above described:

"D. Amarillo Oil Company and Canadian River Gas Company shall enter into an Operating Agreement for the purpose of defining their respective rights and obligations with respect to such leases as are assigned, the terms and provisions of such Operating Agreement to conform with those contained in that certain Operating Agreement dated January 3, 1928, entered into originally between Canadian River Gas Company and Amarillo Oil Company, subject to such changes and modifications thereof as may be deemed necessary or advisable by counsel or agreed upon by the parties; provided, however, that in the event of conflict between the terms and provisions of said Operating Agreement last above referred to and the terms and provisions of the leases to be assigned, it is understood and agreed that the terms and provisions of said leases shall control."

The gas rights on the entire acreage were to be assigned to Canadian free of cost to Canadian but with the obligation upon Canadian to drill a test well on such acreage.

If the well drilled had been an oil well Amarillo Oil Company would have been obligated also to have paid for the well. Exhibit 16.

J. D. THOMPSON, JR., testified that he had recommended that this well be drilled. His testimony is as follows:

> "Q. (March) Did you recommend the dry hole drilled down here by the city limits of Amarillo?
> "A. Yes.
> "Q. I notice Canadian River has some acreage there. Did you think possibly that there was gas there?
> "A. Yes,
> "Q. You wouldn't recommend the drilling of a dry hole if you knew there wasn't any gas there, or had good reason to believe there wasn't any gas there, would you?
> "A. No. * * *" (T. 11168-11169).

Mr. Thompson further testified as follows:

> "Q. Do you know whether or not, Mr. Thompson, that well showed both oil and gas?
> "A. Yes, they had a show of oil and a show of gas, and it showed a favorable structural situation, just about as had been anticipated from our work, * * *" (T. 11169).

The Bivins consolidated lease at the time of the hearing contained approximately 40,000 acres in exploratory drilling blocks of approximately 10,000 acres each which had not been drilled or released. This acreage is designated as undeveloped acreage. The lease provides that the obligation to drill upon any one of these 10,000 acre tracts may be eliminated by surrendering the acreage. The lease also provides that such acreage may be held in force and effect in the absence of drilling by the payment of an annual delay rental of $1 per acre as to each 10,000 acre block upon which a well is due but has not been drilled. (Exhibit 129.)

J. D. THOMPSON, JR. further testified with respect to the exploratory drilling blocks contained in the Bivins consolidated lease as follows:

"Q. (March) * * * Do you consider all that acreage worthless?

"Mr. Keffer: To which acreage are you referring?

"Mr. March: The acreage of the Canadian River Gas Company below the southern boundary of the field (below the fault line).

"The Witness (Thompson): No.

"Q. (March) What do you mean by saying it is not worthless if it is outside the boundary of the field?

"A. In my opinion it has oil and gas possibilities, although it is not proven." (T. 11162.)

Thompson then elaborated still further upon the production possibilities of this acreage. He called attention to the fact that the Helium Dome in Potter County from which the United States Government produces large volumes of gas is also located south of the Potter County fault line and is not within the boundaries of the Texas Panhandle Field. He said that the Helium Dome constituted a local structural high which had trapped a large volume of gas. He also called attention to the fact that there was a well located in Section 37, Block 5 G&M Survey, Potter County, which originally had a good flow of gas. It will be noted from an examination of Commission's Map 95 that this well is located only about one and one-half miles from Canadian acreage south of the fault line (T. 11163-11164).

Thompson also made the following statement:

"Now, it has been quite a problem to me to try to evaluate the oil and gas possibilities of the Canadian River acreage below that fault line. I have spent a lot of time considering it and there have been surface geological surveys made in areas where we have outcrops that permit that and certain areas have shown favorable conditions from the standpoint of surface geology.

"I have also taken into consideration the favorable indications from the standpoint of sub-surface geology such as this anticlinal structure that I have already described, and then there has also been made a magnetometer survey which indicates certain favorable areas and that has been further checked by torsion bal-

ance survey which indicates favorable areas and in several instances these favorable indications by these various methods coincide in a given area and that makes me very reluctant to dispose of that acreage until we have had test wells drilled, and even though the results of one test well on one area might turn out to be a dry hole, it might develop information which would cause me to make—or to recommend a location in that immediate area not far from the dry hole." (T. 11164-11165.)

Thompson further stated that he could not give the Canadian acreage south of the fault line any reserve figure at this time because it was unproven acreage (T. 11168). Thompson stated that the acreage does have production possibilities.

On further redirect and recross examination with respect to Canadian acreage south of the fault line (Vol. 76, pp. 11168-11170) the witness stated:

Q. Well, Mr. Thompson, now, if your estimate of reserves is a correct figure, why is it that you leave out all of this area that you think will be productive of gas?

A. I didn't say I thought it would be productive. I said that I thought it should be explored before we released it.

Q. Hasn't a great part of it been explored?

A. No.

Q. You would consider it too valuable to release?

A. Yes.

Q. Did you recommend the dry hole drilled down here by the city limits of Amarillo?

A. Yes.

Q. I notice Canadian River has some acreage there. Did you think possibly that there was gas there?

A. Yes.

Q. You wouldn't recommend the drilling of a dry hole if you knew there wasn't any gas there, or had good reason to believe there wasn't any gas there, would you?

A. No. You drill a great many dry holes in exploratory work. That's how oil and gas fields are found is just to hop out in the middle of an undrilled area and see what you get, and the use of geology and geophysics merely reduces the hazards a little bit.

Q. Now, so much for that end of the field south of the Potter County fault line.

Mr. Keffer: I wonder if I could ask a question on the Amarillo well?

Mr. March: Why, certainly. Go ahead.

Mr. Keffer: Do you know whether or not, Mr. Thompson, that well showed both oil and gas?

The Witness: Yes, they had a show of oil and a show of gas, and it showed a favorable structural situation, just about as had been anticipated from our work, but where these shows occurred the porosity was so limited—I don't suppose there was more than six inches of formation that showed any porosity at all and that was very low porosity.

By Mr. March:

Q. What was the per cent porosity of that well?

A. I don't know, but I looked at the samples and I could see that it was very tight and just one sample in each instance, as I remembered it, showed some pore spaces in the rock, and I considered that had the porosity and permeability been present we would have had a commercial well. The structural situation was favorable.

Q. That well wasn't drilled on Canadian River acreage, was it?

A. I believe it was.

Q. Mr. Thompson, before we go to the north, I want to ask you this question about the helium dome: Do you think there is any possibility of any drainage between the Panhandle field proper and the helium dome?

A. No.

Q. Why is that?

A. Because there is no interconnection.

Q. How do you know there is no interconnection?

A. The helium dome has a much higher rock pressure than the main Panhandle gas field.

Wallace testified (Vol. 52, pp. 7266-7276) as follows:

Q. Now, what other acreage in the Bivins lease have you classified at $1 per acre?

A. 64,748.34 acres. Generally that acreage that I have classified in "C" classification is below the fault line; that

is, the recognized southwestern boundary of the field and the acreage from the field south to the city of Amarillo, Texas.

Q. And the fault line is the staggered line indicated on Exhibit No. 95?

A. I believe that fault line is as it is staircased by the Canadian River Gas Company but I have used the fault line as nearly as possible that has been adopted by the Texas Railway Commission. A fault line usually runs straight. It doesn't run stairsteps.

Q. All of this acreage is below both of those lines, isn't it?

A. Yes, with the exception of possibly a portion of some of the leases that may extend over the fault line.

Q. Now, this acreage in that Section 190, right immediately north of Amarillo, that is, you say, in your opinion, one that has a value of $1 an acre?

A. At this time I don't think it has a value of more than a dollar an acre.

Q. You would say it even has a value of $1 an acre for gas production purposes?

A. A dollar an acre does not entirely represent the value for gas. I have given it $1 an acre--$1 an acre for this acreage, because it is part of one lease; it is all validated, and there is a great deal of it that is "Wild-Cat," of which you know, and I have considered a dollar an acre was a fair value as a carrying charge, not as a value of gas.

Q. What in your opinion do you define as "Wild-Cat" acreage?

A. Acreage that is not accepted as proven acreage.

Q. As a matter of fact, there is no gas well that has ever been brought in on any of that acreage?

A. No, but there are some dry holes on some of it.

Q. The dry holes have a very definite indication there is no gas in that particular area?

A. No, just in the well.

Q. But every well that has been drilled in that area has been a dry hole?

A. That is right.

Mr. Keffer: Just a minute, Mr. Lange. What do you mean "in that area"?

Mr. Lange: This acreage he has under "C" below the fault line.

Mr. Keffer: You mean in the area on that acreage or in the general area?

Mr. Lange: On that acreage.

Mr. Keffer: There are two different things there. There are gas wells in that area but none of it is on this particular acreage.

By Mr. Lange:

Q. There is no producing gas well that has ever been drilled on what you classified under "C" in the Bivins lease?

A. No.

Q. Do you know the provisions of the Bivins Consolidated lease and what has to be done by the lessee in connection with that lease?

A. Yes, they are to drill or cancel.

Q. To drill or cancel?

A. Yes.

Q. There is no definite obligation for them to drill if they desire to exercise an option to cancel?

A. No.

Q. In any year they so desire they can cancel that particular drilling block or that block of acreage by so notifying the lessor?

A. That is correct.

Q. Without drilling and without any obligation?

A. That is right.

Q. And without any way affecting the remainder of the leasehold?

A. That is right.

Q. Then you still believe that in the light of the history of that particular acreage that you classified as "C" under Bivins, what has happened to it is it is still worth $1 an acre?

A. Yes, I do, because it covers such a large acreage and there are so many unknown quantities. It may be possible a pool may be discovered where that acreage is located.

Mr. Keffer: Could I interpose a question there, Mr. Lange?

Mr. Lange: Yes.

Mr. Keffer: Would you come to the map which is marked

as Exhibit No. 95 and look in Section 37 in G-M Block 5 Potter County, and tell me what you find there on the Commission's map?

The Witness: A gas well is marked there.

Mr. Keffer: What is the size of that gas well?

The Witness: It came in originally purported to be 7,000,000 cubic feet. I don't know what it is at this time.

Mr. Keffer: What is marked on the map?

The Witness: 7,000,000.

Mr. Keffer: 7,000,000?

The Witness: Yes.

Mr. Keffer: Is that well south of the fault line?

The Witness: It is south of the fault line and it is a very deep well.

Mr. Keffer: How far is it from a substantial portion of this "C" acreage that is contained in the Bivins Consolidated lease?

The Witness: Approximately a mile and a half or a mile and three-quarters.

By Mr. Lange:

Q. Whose well is that? Who owns that well?

A. It is purportedly owned by the Humble. I do not know the ownership of it just now. It may still belong to Humble.

Q. Going back to this 190 acres immediately north of the city of Amarillo, do you know anything about the well that was drilled by Canadian River on an acreage adjoining that?

A. Yes, I observed the drilling of that well from practically top to bottom.

Q. You did?

A. Yes.

Q. That was a dry hole?

A. Yes, sir.

Q. And what other drilling operations took place on that particular acreage?

A. On that particular lease?

Q. Yes.

A. There was an old well drilled about 2,000 feet deep, as reported on that map, that seems to correspond with the place on the map where I have indicated there. I think it was drilled by the City of Amarillo. It was a dry hole. It was only drilled 2,000 feet deep.

Q. When was it drilled?

A. I don't have the history of it.

Q. Was it drilled prior to the other well?

A. It was drilled prior to the well of the Canadian River.

Q. How far is that acreage from the nearest producing gas well?

A. This map—if this map was marked up to date—I don't believe it is—indicates it is about seven or eight miles from the helium gas field that is controlled by the United States Government.

Q. Is there any producing gas well closer than that?

A. Not unless that map is not accurate. I don't believe we have marked our map accurately, at least, I have not on the helium pool. I would have to check it. There are more wells in on the helium pool than I see on that map, but I don't know the location. I will say they are not close to that acreage as they are several miles removed.

Q. Now, the Bivins Consolidated lease aside from this acreage that is below the fault line, *covera* acreage above the fault line that is in the producing area, doesn't it?

A. Yes.

Q. And as you stated, this group of acreages that are covered by the Bivins lease below the fault line are subject to the company releasing them if they don't drill or pay delay rentals?

A. Yes.

Q. And you have given that acreage a value of $1 an acre?

A. Yes.

The Trial Examiner: You said something about there being a carrying charge, Mr. Wallace. What do you mean by that?

The Witness: That is a term we use in our industry. We quite often have leases that we don't consider of very much value but yet there is a remote possibility, particularly if they are scattered over large areas where there are

deeper sands or something that they might come in; but yet at the present time, there is nothing to indicate any lease value; for the fact that they are part of one large lease or within or are checker-boarded, we usually call it a carrying charge or a carrying value of a dollar an acre. It doesn't represent the commodity. The oil and gas rights might be worth more, but it might cost more than that to secure a lease from a landowner so we call that a carrying charge in oil field terms.

By Mr. Lange:

Q. When you speak of a carrying charge, that is not to be in any way related to what you term market value?

A. Yes, it goes into the market value with a lease of 313,588.38 acres and having 64,000 of it that is not determined as proven acreage and not in the generally accepted proven acreage. I believe that all Class C acreage probably would sell. The 64,000 acres covers such an enormous area as it does there might be a possibility of some pools coming in.

Q. Let's take the Class C acreage standing alone, what about that?

A. That 64,000 acres amounting to $64,000, I believe there is enough evidence—the well we spoke of I presume is the Humble which will give you some encouragement—

Mr. Keffer: Just a correction there. The Humble at one time owned that but it has been sold to the Government. It serves as part of their helium reserve.

The Witness: I don't know what disposition was made of it. Another factor is that some of the dry holes that have been drilled in there have had some small showing of gas.

By Mr. Lange:

Q. You still value them at $1 an acre?

A. Yes.

Q. Do you think it is good operating management for Canadian River Gas Company to just release a whole block of 60,000 acres like that because they don't want to drill on it?

A. Yes, I think with the enormous proven acreage they have I would release it.

Q. You would just let that go and charge it off?
A. I would.

Mr. Keffer: I didn't get your answer.

The Witness: I said, yes, with a proven—with a large proven acreage I think I would personally consider the lease practically of the same value and accept $64,000 as it is.

By Mr. Lange:

Q. And if they release subsequent blocks, as they have the right to do, that would be good operating management?
A. I don't see that it would affect the producing lease in the least. I think the earnings that property would show —producing property and proven property wouldn't be affected in the least by the surrender of the "C" acreage.
Q. That would wipe out your Class C valuation there?
A. Yes, sir, that is right. If they didn't own it, I wouldn't classify it, but owning it I considered a dollar an acre sufficient.

* * * * *

Wallace further testified (Vol. 52, pp. 7277-7278) as follows:

Q. Now, as I understand from your statement, referring to all of the remainder of the Class C acreage under the Bivins lease, do you know—first of all, on which of those sections there have been any drilling operations heretofore?
A. On Class C acreage?
Q. Yes, C leases.
A. I am afraid I will have to get my own map. I may be able to find it from this one. There is in Section 2, A, B & M 29, there has been a dry hole drilled or indicated as a dry hole on this map. The records show that that well did have some gas but apparently too small to class as a commercial well.
Q. I see.
A. You asked just for the Bivins C acreage?
Q. Yes.
A. In Section 49 of Beatty and Moulten Survey, Block 2, there was a dry hole drilled which is on the Class C acreage, that is all.

Mr. Keffer: How far apart are those two dry holes?

The Witness: Those two dry holes are—

Mr. Keffer: Just approximately. Guess at it, is all. 20 miles?

The Witness: I would say approximately 30 or 35 miles apart.

The well log of Masterson D-4, introduced by Commission Counsel and marked Exhibit 229, is as follows:

This is the best this can be photographed because it is very tightly bound.

4803

Exhibit No. 229

ANADIAN RIVER GAS COMPA
ENGINEERING DEPARTMENT
COMPLETION REPORT

Work Order No 469
Project Commenced Aug 5, 1938
Project Completed Sept. 19, 1938

DIVISION Production
TITLE OF PROJECT Recondition Well
LOCATION Masterson D-4

Contractor: Company tools

Description of Work Completed
Cement bridge in well, take down well fittings. Run 10-3/4" O. D. casing on bridge & cement

Gas Used M.c.f.

CASING & TUBING RECORD

e	Wgt.	Thds per Inch	Casing Run	Pulled	Set At	Cement Record
3/4"	40# & 45½#	8 thd	1465'		1465'	Cemented with 160 sacks quickstrength

PACKER RECORD

Size: Make: Type: Set At:

CLEANING OUT RECORD

Cleaned out From: 1465' To: 1510'

Production Before: ? R.P. 261# After: 100,000 M. R.P. 386#

LINER RECORD

ze	Wgt.	Thds per In.	Liner Run	Pulled	Set At

arks: Put in cement bridge (60 sacks) on top of mud at 1440'. T.D. 1670'. Ran 1465' 10-3/4" casing and cemented with 160 sacks cement. Drilled out plugs & cement to 1510' when well blew out.

Signed by E. H. Adrian 11/4/38 Approved By R A Ford Date 11-5

This is the best this can be photographed because it is very tightly bound.

4805

Exhibit No. 229

WELL RECORD

COMPANY	Canadian River Gas Company
COMPANY WELL NUMBER	4 — N. Y. 134
LEASE	R. B. Masterson "D" — 55
LOCATION	384' fr WL, 270' fr SL, Sec. 106, Blk 0-18, D&P Survey, Potter County, Texas

DATE LOCATION MADE		BY	
ELEVATION	3496'	BY	
DATE DRILLING COMMENCED	10-15-19		11-29-19
ROTARY TOOLS WERE USED FROM		FEET TO	
CABLE TOOLS WERE USED FROM		FEET TO	
NAME AND ADDRESS OF DRILLING CONTRACTOR			

CASING AND TUBING RECORD

SIZE	WGT. PER FT.	THREADS	LANDED AT	CASING PULLED
10			20'	20'
6-1/2			540'	182'
3-1/2			380'	None

OIL AND GAS SAND RECORD

FROM	TO	TOTAL FEET	VOLUME	CUMULATIVE
1640	1645	5		1/2 Mil. Cu. Ft. Gas
1660	1665	5		Gas Sand
1665	1670	5	107,000 MCF	

WATER SAND RECORD

FROM	TO	TOTAL FEET	VOLUME	
416	420	4		Water
435	445	10		Water
692	715	23		Water
735	780	45		Water

TOTAL DEPTH OF WELL	1670'	DEPTH AFTER PLUGGING BACK	
INITIAL PRODUCTION	107,000 M.C.F.	DATE	
INITIAL ROCK PRESSURE	430#	DATE	

REMARKS (DRILL STEM TEST RECORDS, PACKERS, PLUGGING BACK, LOST TOOLS, CROOKED HOLE DATA, ETC.)

(Drilled by Amarillo Oil Company)

(See Supplemental Report on Reconditioning Well)

G118

G118
229

FEDERAL POWER COMMISSION
EXHIBIT NO. 229 (FOR IDENTIFICATION)
DATE IDENTIFIED

APPROVED BY

Exhibit No. 229

MASTERSON D-4 FORMATION RECORD

FROM	TO	TOTAL FEET	FORMATION
0	38	38	Soil
38	44	6	Red rock
44	48	4	Lime
48	58	10	Grey shale
58	145	87	Red rock
145	150	5	Gyp
150	155	5	Red rock
155	160	5	Gyp
160	270	110	Red rock
270	285	15	Water sand
285	310	25	Red rock
310	324	14	Gyp
324	370	46	Red rock
370	380	10	Red rock & gyp
380	395	15	Gyp
395	410	15	Red rock
410	445	35	Gyp & gravel
445	460	15	Red rock
460	485	25	Gyp
485	490	5	Red rock
490	510	20	Gyp
510	520	10	Red rock
520	545	25	Gyp
545	550	5	Red rock
550	580	30	Gyp
580	585	5	Red rock
585	605	20	Gyp
605	610	5	Red rock
610	657	47	Gyp
657	692	35	Brown shale
692	715	23	Quicksand-water
715	725	10	Gumbo
725	735	10	Red rock
735	780	45	Quicksand-water
780	786	6	Red rock
786	805	19	Blue gyp
805	940	135	Red rock
940	960	20	Gyp
960	1020	60	Red rock
1020	1045	25	Gyp
1045	1095	50	Red rock
1095	1140	45	Gyp
1140	1150	10	Red rock
1150	1170	20	Gyp
1170	1185	15	Red rock
1185	1205	20	Gyp
1205	1215	10	Red rock
1215	1235	20	Gyp
1235	1240	5	Red rock
1240	1250	10	Gyp
1250	1290	40	Red rock
1290	1310	20	Gyp
1310	1360	50	Sand
1360	1370	10	Red rock
1370	1420	50	Sand
1420	1425	5	Red rock
1425	1470	65	Brown rock
1470	1490	20	Red rock
1490	1615	125	Lime
1615	1640	25	Blue shale
1640	1645	5	Gas sand - 1/2 mil. Cu. Ft. Gas
1645	1660	15	Blue shale
1660	1665	5	Gas sand
1665	1670	5	Gas sand - 107,000 M.C.F. gas

(Well completed and shut in November 29, 1917.)

The well log of Bivins A-18, introduced in evidence by Commission Counsel and marked Exhibit 221, is as follows:

4811

Exhibit No. 221

WELL RECORD

CANADIAN RIVER GAS COMPANY

WELL NUMBER 2A

OTHER WELL NUMBER

Bivins "A"

LEASE NUMBER 50

LOCATION 2619' f. N., [illegible]' f. E., Sec. 17, Blk M-20, G&M Survey, Potter County, Texas

MAP CO-ORDINATE 0-13

DATE LOCATION MADE 8/28/36 BY W. M. Clifton

ELEVATION 3068' BY W. M. Clifton

DATE DRILLING COMMENCED 9/30/36

DATE DRILLING COMPLETED 11/5/36

ROTARY TOOLS WERE USED FROM FEET TO FEET, AND FROM

CABLE TOOLS WERE USED FROM FEET TO FEET, AND FROM

NAME AND ADDRESS OF DRILLING CONTRACTOR Phoenix Drilling Company, Amarillo, Texas

CASING AND TUBING RECORD

20"	90#	8 thd	42'9"	42'9"		
16"	70#	8 "	225'		225'	Cemented with 100 sacks cement.
15½"	70#	8 thd	203'10"	None	203'10"	Cemented with 50 sacks cement.
12½"	52#	" "	543'9"	543'9"		
10"	45#	8 "	1342'1"	1342'1"		

OIL AND GAS SAND RECORD

From	To	Total Feet			Remarks
120	390	270			Sand
430	440	10			Sand
535	545	10			Sand
825	865	40			Sand
875	900	25			Sand
955					Heaving sand
1800	2250	450			Show of gas
2370	2610	240			Gas Increase
					Final Gauge 1.P 18,720 MCF

WATER SAND RECORD

From	To	Total Feet	Volume
88			Hole full of water.
115	160		Sand Water
430	440		Sand water.

TOTAL DEPTH OF WELL 2720

DEPTH AFTER PLUGGING BACK

INITIAL PRODUCTION 18,720 M.C.F. DATE 11/21/36

INITIAL ROCK PRESSURE 413# DATE 11/21/36

REMARKS (SHOT RECORDS, PACKERS, PLUGGING BACK, LOST TOOLS, CROOKED HOLE DATA)

APPROVED BY

C H Alderton

BAD PRINT

Exhibit No. 221

FORMATION RECORD

From	To	Total Feet	Formation
0	12	12	Cellar
12	55	43	Sand
55	115	60	Sand
115	180	65	Sand
	190	10	Sand
	200	10	Red rock
	213	13	Gyp
	215	2	Gyp
	295	80	Red rock
	370	75	Red rock
	420	50	Red rock
	430	10	Red rock
	440	10	Sand water
	530	90	Red rock
530	535	5	Red rock
535	545	10	Red sand
545	550	5	Red shale
550	555	5	Gyp
555	558	3	Gyp
558	561	3	Red rock
561	595	34	Gyp
595	598	3	Red rock
598	615	17	Gyp
615	665	50	Gyp
665	675	10	Gyp
675	710	35	Gyp
710	725	15	Red rock
725	750	25	Gyp
750	785	35	Gyp
785	825	40	Blue shale
825	835	10	Hard sand-Water
844	865	21	Sand
865	875	10.	Shale
875	885	10	Sand
885	895	10	Sand
895	900	5	Sand
900	905	5	Red rock
905	908	3	Gyp
908	945	37	Red rock
945	955	10	Red rock
955	980	25	Heaving sand
980	1000	20	Sand
1000	1020	20	Red rock
1020	1045	25	Red rock
1045	1075	30	Red rock
1075	1105	30	Red rock
1105	1115	10	Red rock
1115	1135	20	Sand
1135	1150	15	Red rock
1150	1175	25	Sand
1175	1185	10	Red rock
1185	1205	20	Red rock & salt
1205	1235	30	Red rock & salt
1235	1260	25	Red rock
1260	1263	3	" "
1263	1265	2	Gyp
1265	1280	15	Red rock & salt
1280	1300	20	" " "
1300	1320	20	" " "
1320	1345	25	Red sand
1345	1365	20	Sand
1365	1375	10	Sand
1375	1395	20	Sand
1395	1400	5	Red rock
1400	1465	65	Red rock & sand
1465	1515	50	" " "
1515	1560	45	Salt & shale
1560	1590	30	Salt
1590	1620	30	Anhydrite
1620	1630	10	Red rock & Salt
1630	1715	85	Salt & gyp
1715	1735	20	Salt & red rock
1735	1765	30	Gyp
1765	1780	15	Blue shale
1780	1795	15	Dark blue shale
1795	1800	5	Red rock
1800	1820	20	Gas
1820	1830	10	Red rock
1830	1835	5	Green shale
1835	1850	15	Red rock
1850	1905	55	Red rock & gyp
1905	1960	55	" " & blue shale
1960	1980	20	" " " "
1980	2000	20	Lime broken
2000	2005	5	Red rock
2005	2020	15	Lime broken
2020	2060	40	Broken lime
2060	2110	50	" "
2110	2135	25	" "
2135	2150	15	Lime
2150	2185	35	Lime
2185	2210	25	"
2210	2240	30	"
2240	2252	12	"
2252	2275	23	"
2275	2300	25	"
2300	2315	15	"
2315	2330	15	"
2330	2360	30	"
2360	2390	30	"
2390	2420	30	"
2400	2460	60	"
2460	2510	50	"
2510	2555	45	"
2555	2565	10	"
2565	2585	20	"
2585	2600	15	"
2600	2603	3	Red rock
2603	2605	2	Lime
2605	2625	20	Lime
2625	2650	25	"
2650	2654	4	"
2654	2658	4	Green shale
2658	2665	7	Red rock
2665	2675	10	Lime
2675	2715	40	Granite wash
2715	2720	5	" "

2720 Total depth.

FEDERAL POWER COMMISSION DOCKET NO.
EXHIBIT NO. 221 (FOR IDENTIFICATION)

...SSION

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221

60. Amortization, Depreciation and Depletion—Canadian.

Accumulated Depreciation and Depletion and Its Application to the Original Cost of the Producing and Gathering Properties of Canadian as of December 31, 1938.

For the respondent there was introduced and received in evidence (Vol. XCVIII, p. 15279) Exhibit No. 272, entitled as above, and prepared by Witness H. E. Roberts.

The identity and qualifications of Witness Roberts (Vol. LXXXXIV, pp. 14413, et seq.) are as follows:

Full name: H. Emmett Roberts, 39 Broadway, New York City; age 44; graduate of East Orange, N. J., High School and Sibley College, Cornell University, with M.E. Degree in 1918. Upon graduation entered employ of Westinghouse Lamp Company, Bloomfield, New Jersey, and from there went with Thomas A. Edison Company, West Orange, N. J. In the summer of 1919 entered employ of FB&D, Inc., where he has remained since. His work with FB&D has been in the capacity of an engineering specialist in the valuation of industrial and public utility properties, including the valuation of pipe lines for public utilities, oil refineries and industrial plants, distribution properties of gas, water and electric companies, oil and gas wells, electrical and miscellaneous equipment of public utilities and industrial plants, and retrospective appraisals.

Some of the principal companies on the valuation of which he has worked are: Atlantic Refining Company; Livingston Oil Corporation; Standard Oil of California; Peoples Natural Gas Company; Keen & Woolf Oil Company; Oklahoma Natural Gas Company; Okmulgee Gas Company; Kansas City Gas Company; Richfield Oil Company of California; Hope Natural Gas Company; Arkansas Natural Gas Company; New York Steam Company; Ponca City Gas Company; Amarillo Gas Company; West Plains Gas Company; Sinclair Consolidated Oil Company; Ohio Fuel Gas Company; Panhandle Pipe Line Company; the East Ohio Gas Company; Philadelphia Suburban Water Company; United Fuel Gas Company; Natural Gas Company of West Virginia; Indianapolis Gas Company; Indiana Gas Utilities; Pennsylvania State Water Corporation; Colorado Interstate, and Canadian.

In connection with the valuation of pipe lines he made field studies of the performances attained in the construction of pipe lines. One of these studies covered the whole construction period of a 60-mile long pipe line (4 in.) for the Carbide and Carbon Chemicals Corp. from Leach, Kentucky, to South Charleston, West Virginia.

Mr. Roberts has worked with Mr. Rhodes in connection with the reproduction cost appraisals of the pipe line properties of Canadian and Colorado Interstate. He has spent a good part of his time during the last year or so in connection with the work which FB&D has been doing in the present rate case, beginning in March, 1939. As assistant to Mr. Rhodes he was Field Engineer in Charge and worked on depreciation, that is, condition of the property, as well as on reproduction estimates. (Vol. LXXXXIV, pp. 14415, et seq.)

Exhibit 272 consists of three statements numbered 1, 2 and 3.

Statement No. 1 is captioned: "Canadian River Gas Company Accumulated Depreciation and Depletion of the Original Cost of Production and Gathering System Property as of December 31, 1938."

Statement No. 2 is captioned: "Canadian River Gas Company Segregation of the Original Cost of the Production and Gathering Properties to Direct Costs and General Construction Costs, as of December 31, 1938."

Statement No. 3 is captioned: "Canadian River Gas Company Accumulated Depreciation of Original Cost of General Properties and its Allocation by Property Systems, as of December 31, 1938."

Statement No. 1 is as follows:

Statement No. 1
Canadian River Gas Company
Accumulated Depreciation and Depletion of the Original Cost of Production and Gathering System Property as of December 31, 1938
Summary of Accounts

Item No. (1)	Account No. Company (2)	Description (3)	Original Cost Adjusted (A) (4)	Accumulated Depreciation and Depletion Per Cent (5)	Accumulated Depreciation and Depletion Amount (6)
	Production System				
1.	205	Leaseholds	$ 5,075,906	36%	$ 1,827,326
2.	211	Gas Well Construction	2,189,659	31	678,794
3.	212	Gas Well Equipment	931,900	31	288,889
4.	209	Field Measuring Station Structure	8,543	17	1,452
5.	215	Field Measuring Station Equipment	46,854	11	5,154
6.	216	Drilling and Cleaning Equipment	24,244	....	....
7.	218	Field Measuring Station Land	100	....	....
8.		Total	$ 8,277,206		$ 2,801,615
9.		General Property (Allocated) (B)	56,273	25	14,169
10.		Total Production System	$ 8,333,479		$ 2,815,784
	Gathering System				
11.	206	Rights of Way	$ 13,485	....	....
12.	213	Field Line Construction	282,334	7	$ 19,763
13.	214	Field Line Equipment	864,495	7	60,515
14.	221	Field Compressor Station Structures	2,969	18	534
15.	224	Field Compressor Station Equipment	13,779	16	2,205
16.		Total	$ 1,177,062		$ 83,017
17.		General Property (Allocated) (B)	44,781	22	9,855
18.		Total Gathering System	$ 1,221,843		$ 92,872
19.		Total Production and Gathering Systems	$ 9,555,322		$ 2,908,656
20.		General Construction Costs Applicable to Production and Gathering System	586,193		161,041
21.		Total Original Cost of Production and Gathering System Property	$10,141,515		$ 3,069 697

Notes: (A) As shown on Exhibit No. 183, adjusted as shown on Statement No. 2 attached.

(B) As shown on Statement No. 3 attached.

This Exhibit 272 is prefaced by an explanatory statement of H. E. Roberts. (Vol. LXXXXIV, pp. 14418, et seq.) We quote somewhat at length from this explanatory statement:

"Scope of This Exhibit

This exhibit shows the depreciation and depletion accumulated at December 31, 1938, in the production and gathering facilities of Canadian River Gas Company, which are described in Exhibit No. 89 by Max K. Watson, and its application to the original cost of these facilities, presented by W. A. Lusk in Exhibit No. 183.

"The depreciation accumulated in the property was determined by studies of the extent to which the physical phenomena that ultimately lead to the retirement of items of property had progressed. Depreciation as determined is separate and distinct from accruals for amortization against the possible termination of or major changes in the Canadian River business.

"Depletion computed herein refers to the using up of the gas supply and is based on the gas withdrawn from the Panhandle gas field from May 31, 1928, to December 31, 1938, in relation to the estimated recoverable gas reserves at the first date.

"Leaseholds

"Accumulated depletion in leaseholds has been computed each year from 1928 to 1938, inclusive, in direct ratio to the relation of gas withdrawn from the Panhandle field each year to the gas reserves remaining at the beginning of each year. This computation is based on the depletion of the field as a whole as testified by other witnesses.

"The original gas reserves estimated as recoverable at 50-lb. gauge by J. D. Thompson in his Exhibit No. 207 less the gas withdrawn through 1927, as shown by C. J. Peterson in Exhibit No. 206, gives the remaining gas reserves as of January 1, 1928. The annual withdrawals in that year, as shown by Mr. Peterson in Exhibit No. 206, divided by the reserves as of January 1, 1928, then gives a ratio which indicates the percentage depletion of the gas reserves in the field in 1928. The

successive reduction of the remaining reserves at January 1 by the annual withdrawals each year, as reported by C. J. Peterson in Exhibit No. 206, gives the reserves remaining at January 1 of each of the following years. Successive division of the reserves at January 1 each year into the gas withdrawn in that year, gives the percentages of depletion for each year since 1928.

"The depletion ratios determined as above, applied to the Company's remaining investment at January 1 each year, gives the depletion sustained by the Company in that year except that in the first year of the Denver line operations the Company's investment at June 1 in its presently held acreage (as of December 31, 1938) was depleted at seven-twelfths of the rate of depletion in the field as a whole. Deduction of this Company depletion during 1928 from its June 1 investment, plus the investment added during the year, gives the Company's remaining investment in leaseholds at January 1, 1929. Thereafter the successive deduction of depletion sustained and the addition of new investment added December 31, 1938, of $3,248,580 which is 64 per cent of the original cost of the leaseholds held at that date. Therefore, the accumulated depletion in the Company's leaseholds at that time is taken at 36 per cent.

"Land and Rights of Way

"No depreciation on land and rights of way has been allowed in this exhibit.

"Gas Well Construction (Account 211)

"Gas well construction which comprises the intangible well drilling costs is depleted by the same method as leaseholds. This determination resulted in 31 per cent depletion as of December 31, 1938.

"Gas Well Equipment (Account 212)

"Owing to the difficulties of physical examination of gas well equipment, this equipment has not been depreciated but has been depleted in accordance with the depletion accumulated in the gas well construction account.

"Buildings and Structures

"The depreciation existing in buildings was determined by a detailed inspection of the buildings and structures in the field. Field inspections were tabulated and summarized and the condition of the buildings determined in groups such as those at a compressor station. In determining such depreciation existing in these buildings there was taken into account the depreciation found to exist in the various parts, the relative extent to which parts contributed to the whole cost of the structure and the relative extent to which the individual structures contributed to the total cost of the whole group.

"Field Line Construction and Equipment

"The depreciation suffered by the Company's production system pipe lines was determined from inspections made in the summer of 1939. Inspection points, numbering 125, were chosen on those lines spaced at intervals representing roughly $10,000 in cost. On the 22-inch main gathering line this spacing was three-eighths of a mile and on the 6-inch line about one and seven-eighths miles. On each size of line the locations of the points of inspection were at substantially uniform intervals. The locations were chosen in the office from maps and were marked out in the field from the nearest available landmarks.

"At each location a hole was dug uncovering the pipe for a length of about 4 feet of width and depth sufficient to permit inspection of the pipe on the bottom as well as on the sides and the top. In each test hole the pipe was thoroughly cleaned for a length of about 3 feet and in this length the central 24-inch section of pipe was inspected. Records were made as to the general character, extent and severity of corrosion and of the principal conditions affecting corrosion in that location. The depths of many deepest pits were measured and recorded, generally 30 in each 24-inch section. This number was chosen as necessary to insure a dependable knowledge of the depths of the deepest pits. In measuring these pits special care was exercised to clean them

out thoroughly at the bottom thus insuring a full measure of depth.

"The depreciation sustained by the pipe lines was determined from a consideration of the field inspections above described. The records of the field work were tabulated and summarized. They were subjected to study and analysis both scientific and practical. Consideration was given to the many factors affecting depreciation through corrosion which are described in the succeeding paragraphs.

"Renewals of pipe are most commonly the result of a troublesome succession of leaks caused by corrosion. As leaks occur they are stopped by bolting band clamps around the pipe with a rubber backing over the leaks. Sometimes two or more leaks develop at widely separated dates in the same joint of pipe. The development of leaks first occurs in stretches of lines where for various reasons local conditions are favorable to corrosion. These are called 'hot spots' and range from a few joints to thousands of feet in length. When the leaks occur with troublesome frequency not only is the pipe in the 'hot spot' itself removed but also pipe for an appropriate distance on either side. In practice the worst joints of pipe may have two or more leaks. Stretches of pipe 100 feet long may contain five to ten leaks and other stretches may have no leaks at all. Some pipe is suitable for reuse with a simple cleaning operation, some requires welding the pits before it can be reused and other pipe is reduced to junk.

"The progress of corrosion has universally been found to fall off with age. When pipe is first buried it starts to corrode rapidly. As time goes on the intensity of corrosion slows down. Not enough inspections were made of the Company's lines nor was there enough range in age to permit a field determination of the extent to which this corrosion slows down. However, the United States Bureau of Standards has investigated this characteristic of slowing down in corrosion as related to 47 soils scattered throughout the country. There were only 6 soils found in which the depth of pits increased

more than 50 per cent through doubling the age and these soils are decidedly unusual in their characteristics. In soils characteristic of Canadian River's territory the increased depth with doubling the age was much less than 50 per cent. Accordingly, it was considered in determining the depreciation accumulated in the Company's pipe lines that corrosion would slow down to such an extent that doubling the age would result in not more than a 50 per cent increase in the depth of pits.

"It is also the universal experience that the greater the lengths of pipe examined on inspection the greater will be the average depths of the deepest pits found. A study of the relative depths of the deepest pits in the 24-inch sections was made, from which was determined by scientific analysis the average depths that could be expected in greater lengths of the Company's pipe of 10, 20, 40 or 50 feet, as the case may be. This study also determined the number of pits required to be welded in reconditioning.

"Through a correlation and application to the field insections of the rules of corrosion outlined above by the proper use of engineering methods, it was determined that the Company's production system pipe lines had depreciated 7 per cent.

"Field Compressor Station Equipment.

"The condition of this equipment was determined by field inspection and observation of all parts above ground. Underground piping was conditioned as having 23 per cent greater depreciation than the field line pipe, the difference having been determined from a comparison of the condition of the underground pipe in the main line station at Bivins and the transmission line pipe.

"Minor Property Accounts

"The depreciation existing in the minor property accounts was in general determined by observation as in the major accounts, in detail appropriate to the importance of the respective accounts.

"General Construction Costs

"The depreciation determined as having accumulated in Canadian River's depreciable property is based on the system as a continuing property without important change except as to extensions. Items of equipment retired in such property in the natural gas business are commonly replaced in kind and accordingly only a portion of the undistributed construction costs depreciates with the property itself. The replacement of that property involves little or no engineering cost and little or no interest. Portions of the property, however, that are retired and replaced with property of a different type, which occasionally takes place, involve a repetition of most of the undistributed construction costs. All things considered, one-half of the total amount of undistributed construction costs is appropriately considered as depreciating with the depreciable property.

"General construction costs applying to the original cost of depleted items have been depleted with the property to which they apply.

"Adjustments to Original Costs

"To apply the determined extent of depreciation and depletion to original cost it was necessary to segregate therein certain general construction costs which had been distributed to the several accounts, which adjustment is shown on the attached Exhibit No. 2.

"The general property allocated to systems in Exhibit No. 183 has been adjusted and reallocated on Statements Nos. 3 and 4 herein on account of the Fritch and Masterson Camps which were not included as part of the general property in Exhibit No. 68.

"Summary

"The percentages of depreciation accumulated in the depreciable property and the percentages of depletion accumulated in the depletable property are summarized and applied to original costs account by account on Statement No. 1 to obtain the accumulated amount of depreciation or depletion shown the several classes of

property. The total accumulated depreciation and depletion in the original cost of the producing and gathering properties of Canadian River Gas Company at December 31, 1938, herein considered, determined as set forth above and supported by Summary Statement No. 1, amounted to $3,069,697."

Roberts was examined and cross-examined at length on Exhibit No. 272 and his statement with reference thereto quoted above. (Vol. LXXXXIV, pp. 14413-14438; Vol. XCVII, pp. 15023-15122; and Vol. XCVIII, pp. 15214-15240.)

Roberts restated that he had depleted the leaseholds, wells and well construction account in accordance with the methods described by him in his general statement which was a new computation different than in any of the exhibits on reproduction costs of the Denver pipe line properties, but that with respect to the gathering lines, the compressor stations and the general property and other miscellaneous properties, the same methods were used in arriving at depreciation, as testified to by Mr. Rhodes when he explained such methods in connection with his Exhibit No. 68 concerning Canadian properties and Exhibit No. 70 concerning Colorado Interstate properties. The percentages of depreciation set forth in the exhibit were those arrived at and the conclusion reached by Mr. Rhodes and Mr. Roberts as a result of observations of their assistants. The Masterson and Fritch camps are not in Exhibit 68, so depreciation as to them after conference with Mr. Rhodes was determined separately on the same basis of depreciation as set forth in Exhibit 68. Mr. Rhodes' explanation with reference to Exhibits 68 and 70 is applicable to Exhibit 272. (Vol. LXXXXIV, pp. 14431-14433.)

Mr. Roberts was in charge of field work under Mr. Rhodes and worked with him in setting the final figures for depreciation. Most of the work was done in 1939. (Vol. XCVII, p. 15028.) In most other instances in which he was connected with the valuations of property there was involved an estimate of reproduction cost new. (Vol. XCVII, p. 15037.) In connection with the field inspections indicated in Exhibit 272 this involved an inspection of the major buildings, the pipe lines and the measuring stations, a chronological list of which was made and an inspection made

of every fourth building and measuring station in the order in which constructed. The accumulated depreciation figure given in Exhibit 272 is the converted per cent condition used by Mr. Rhodes in his reproduction cost new estimate; that is, where there is a 93% condition related to reproduction cost new, there is a 7% accumulated depreciation figure. (Vol. XCVII, p. 15038.) Mr. Roberts did not, except in one instance, accompany the inspection gangs on the inspection trips. These were in charge of Mr. W. T. Smith of FB&D. The method, however, was the same, as explained by Mr. Rhodes in his testimony. (Vol. XCVII, pp. 15039, et seq.) In connection with the pits discovered by inspection in the pipe lines it was not necessary to determine the age of the pits in order to determine the condition of the pipe lines or the percentage of depreciation, as the age of the pits under the method used was immaterial. (Vol. XCVII, pp. 15042, et seq.)

Witness Roberts testified on cross-examination: (Vol. XCVII, p. 15030.)

Q. Now, in connection with these several valuation matters in which you participated, did you ever have occasion to compute any service lives of property, units of property?

A. Service lives?

Q. Yes.

A. I have done some studies on the amount that the companies wished to set up on their books for depreciation rate.

Q. Involving the computing of service lives as an engineering matter?

A. Just a determination of what was the proper allowance to set up on the books to cover depreciation.

Witness Roberts further testified on cross-examination: (Vol. XCVII, pp. 15040-15045.)

Q. I want particularly to confine myself at this time to the method that you pursued in relating those inspection figures to your so-called accumulated depreciation.

A. This was done in exactly the same way as it was done on the estimates of reproduction of the Canadian River transmission, and the Colorado transmission—exactly the same as Mr. Rhodes testified.

Q. You followed the same theory that he had with reference to the deceleration of the corrosion that takes place in the field lines?

A. That's correct.

Q. In other words, your inspection made in 1939, related the per cent condition as of December 31, 1938?

A. That is correct. At least, we used it for that.

Q. You used it for that. Well, now, these determinations as to corrosion, as I recall Mr. Rhodes' version of that, you determined that after a certain period of time corrosion would decelerate, is that right?

A. No, not exactly that, not after a certain period of time.

Q. Well, when?

A. As soon as the pit is started it forms a little protection there and the penetration from that time on slows up.

Q. It decelerates, then, as he put it?

A. That's right.

Q. How long will that continue before the deceleration begins; or, once you have a pit, how long will it be before there will be deceleration?

A. As soon as the pit starts, there is sort of a scale that usually forms over that and there are other factors that enter into it, it decelerates at that time—it doesn't decelerate at that time, from that time on it decelerates.

Q. From what time on?

A. From the time there is some pit starting and some material in that pit.

Q. In other words, prior to that time there is acceleration of the pit, or what takes place?

A. It is not acceleration. When the pipe is put in the ground—

Q. All right.

A. —the depreciation starts—

Q. What do you mean by the depreciation starts?

A. I mean depreciation. The principal thing being pitting, one of the principal things—

Q. When you say "depreciation," you mean the pitting starts?

A. The pitting would start, and when that starts, usually in a pit there is some scale and other matter which tends to decelerate that.

Q. All right, now, at the time you made this inspection of the field lines in 1939, how could you determine how long

any of those pits had been—or, how long prior to that time the pits had formed?

A. I didn't need to know.

Q. You didn't need to know that?

A. No.

Q. Why?

A. Because I know from that time on it was going to decelerate and by doubling the age the pit would only go half again as far as it had gone.

Q. Yes, but if you didn't know when that pit had actually started on its course on that pipe, how do you know when it will stop?

A. I don't need to know that. I don't need to know when it is going to stop.

Q. Well, then, how can you determine your per cent condition of that pipe, or the depth of the pit, or how far that pit will eventually go?

A. I know because there is a certain depth at that particular time, and we used a formula which is a very conservative formula of doubling the age that the pit would only penetrate fifty per cent further.

Q. Although you don't know how long that pit had been in the actual process of either forming or how long it had been on the pipe at the time you made your inspection?

A. There is a period covered there. It could be from zero to a hundred and it might be from 1 to 50, but the relation between those things is what we got.

Q. You pay no attention or give no consideration whatsoever in making that determination as to that pit inspection as to how long the pit had been on the pipe at the time of the inspection?

A. No, sir.

Q. It is not necessary to do that to arrive at your per cent condition in utilizing your formula?

A. No.

Q. And the time element doesn't enter into that at all?

A. Time is expressed as the speed of the penetration. As I stated, it decelerates Of course, the deceleration, the time element is considered in that, but that is the extent, the rate is something having to do with time—speed.

Q. Some of these pits you inspected in 1939 were still in the process of decelerating at that time?

A. In 1939?

Q: Yes.

A. Yes.

Q. Well, how much further, then, in the future will that deceleration continue?

A. How much?

Q. Yes, how long?

A. It would continue to decelerate until the time it becomes necessary to remove the pipe, when the pit has gone through the wall, and at such time as it is advisable to remove the pipe. Of course, then the pipe is out.

Q. That is true, but this inspection made in 1939 where you found certain pits that were at that time decelerating, that deceleration would continue for some period in the future?

A. Yes.

Q. Do you know how long?

A. I didn't need to know how long.

Q. You didn't need to know how long?

A. No, all I was interested in was when it would get through the pipe.

Q. You didn't need to know in determining your per cent condition how long that would take?

A. No.

Q. And in determining that per cent condition you arrived at it from that particular physical inspection?

A. From the inspections and correlated data.

Q. And you didn't take into consideration the age of the pipe; how long it had been in the ground?

A. No.

Q. You limited your determination of per cent condition to that physical inspection?

A. And other correlated facts.

WITNESS ROBERTS further testified: (Vol. XCVIII, pp. 15241-15278.)

Q. You have Exhibit 274 before you, Mr. Roberts?

A. I have, Mr. Lange.

Q. This Exhibit 274, as I understand it, relates to the accumulated depreciation as you state, on an hypothetical resale system applicable to the producing and gathering facilities of Canadian River Gas Company?

A. That isn't what the exhibit reads.

Q. Well, what does it—

A. It says: "Canadian River Gas Company accumulated depreciation and depletion and its application to equivalent original cost of producing and gathering facilities for resale gas alone as of December 31, 1938."

Q. Maybe I should have stated it differently. I will ask you this, then, first: The producing and gathering facilities of Canadian River Gas Company have not been utilized exclusively for resale gas alone, have they?

A. No, sir.

Q. Neither in the past nor at the present time?

A. No, sir.

Q. Very well. This exhibit contemplates, however, the use of those facilities for resale gas alone?

A. Yes.

Q. And sets forth some difference, first of all, in property units as distinguished from the use of these facilities for all gas?—as set forth in Exhibit 272. Isn't that correct?

A. Yes, sir, it is based upon the property described in Exhibit No. 121 by Mr. Max K. Watson and their application to the equivalent original cost as presented in Exhibit 193 by Mr. William A. Lusk.

Q. Yes, and the difference in property units that would be utilized under a resale system alone is set forth in Mr. Rhodes' Exhibit 98, isn't it? Isn't that correct?

A. 98?

Q. Yes.

A. I don't recall that exhibit.

Q. "Denver Pipe Line for Resale Only." I beg your pardon, that doesn't apply to production and gathering properties.

A. That refers to Exhibit 121 by Mr. Max K. Watson.

Q. Now, I note that under Statement 1, "Leaseholds," Item 1, you have original cost of leaseholds in your Exhibit 274 at $5,075,906 and accumulated depletion of 36 per cent, converted to dollars, $1,827,326, is that right?

A. That's right.

Q. Well, I see that that is exactly the same, both original cost as well as accumulated depreciation that you have on—depletion, I mean—

A. Yes, sir.

Q. —that you have set up in your exhibit 272 applying to sales of all gas.

A. That is correct.

Q. Would you include the same property here for the resale gas as you do to the sale of all gas?

A. Yes. I applied these percentages to the original cost in the exhibit prepared by Mr. Lusk, No. 193.

Q. Yes, you utilized the same figures that Mr. Lusk has set up which in turn contemplated no allocation whatsoever as between the utilization of these,—of this item of property—these leaseholds, for all gas, as distinguished from resale gas alone?

A. No. Those leaseholds would have been required for resale gas alone.

Q. All of the leaseholds?

A. Yes.

Q. All right, then, in your opinion would those leaseholds have lasted just as long and you would have had the same accumulated depreciation applicable if you related the use of all gas, or to resale gas alone?

A. Taking this property as a whole, why, those percentages would apply against both.

Q. All right, let's say that your opinion is correct, that you would have to have all of the leaseholds in each instance for all gas as well as resale.

A. Yes.

Q. All right, but then we move to your depletion of those leaseholds. How can you say that you would deplete those leaseholds exactly in the same fashion for the same period of time in the resale gas estimate alone as you do for the all gas estimate?

A. If there is drainage in the field and they didn't take it out for one purpose, someone else would take it out for another purpose.

Q. Well, then, the matter of withdrawal or the rate of withdrawal didn't interest you at all, did it?

A. I took the withdrawals each year as compared to the reserves at the start of that year.

Q. Don't you think there would be a different rate of withdrawal in connection with contemplation of all gas sales as distinguished from resale gas sales alone?

A. This refers to the withdrawals for all types of gas.

Q. Yes, I know, Exhibit 272, but when you move over to Exhibit 274 you are limiting yourself to resale gas alone.

A. This is the property which would be required for resale gas alone.

Q. I say, let's assume for the sake of argument you would have to have those same leaseholds.

A. Yes.

Q. But you would still deplete those leaseholds in the same fashion at the same rate and on the same basis whether they applied to all gas sales and the withdrawals under that as distinguished from your resale gas sales and the withdrawals under that character of system?

A. That's what I have done in this exhibit, applied the same percentage of depletion.

Q. All right, even though you had the same base. What I want to know is whether in your opinion that would be a correct calculation in both instances; be exactly the same depletion?

A. That is so considered here.

Q. I know, but you set this up. I want to know what opinion or reason you have for that.

A. I have taken the field as a whole and based it on the basis of withdrawals.

Q. You made no distinction as between the withdrawals that would take place under resale gas distinguished from all gas sales?

A. These are both depleted the same.

Q. Well, are the withdrawals at the same rate under resale as they are under all sales?

A. Withdrawals from the field are.

Q. They would—you say—

A. I say, they have been. I based this on the actual withdrawals from the field.

Q. That is in your Exhibit 272, where you have all gas. Now we are moving to Exhibit 274 where you confine yourself to resale gas alone. You say the rate of withdrawals are the same?

A. It is based upon the amount of gas that was taken from those leases—from the entire field.

Q. This is just an assumption under Exhibit 274. You had no experience there.

A. I have applied the same rate of withdrawals as I did the other exhibit.

Q. I want to know why. That's the whole thing, I just want to know why.

A: Because that represents the fair amount of depletion applying to those leaseholds.

Q. And it bears no relation to what the difference would be under such a system?

A. Will you repeat that?

Q. It bears no relation to what the difference in rate of withdrawals or amounts there would be under a resale system?

A. Well, if the gas wasn't withdrawn for one purpose it might have been withdrawn for another purpose. It still would have been depleted.

Q. But your problems as to field are in the picture in your Exhibit 272 where you have accurate figures on withdrawals.

A. Yes, sir. We have taken those same ones as the withdrawals as applying to these leaseholds.

Q. You computed your depletion in Exhibit 272 on actual figures. You had actual figures on withdrawals in Exhibit 272, didn't you?

A. As accurate as the geologists could give us.

Q. And you began with an estimate or estimates of your geologists as to reserves?

A. Yes.

Q. And computed your figures in Exhibit 272 to give you the accumulated depletion?

A. That is right.

Q. Now, then, you have no actual figures, or none at all, as to withdrawals that would occur under your resale estimate, do you?

A. Those leases would have been required for—

Q. I am not asking you about the leases. We'll concede you would need the same leases just for the sake of argument. We don't concede it, but for the sake of argument, the same leases are there.

A. We might have reduced the amount of depletion there. That wouldn't have—

Q. You would have?

A. We could have done it another way.

Q. You could have, but you didn't.

A. I think this is the proper way.

Q. You didn't take into consideration, then, what such withdrawals would be as distinguished from your all gas sales?

A. I took the total withdrawals from the field to date.

Now, if you had taken less withdrawals there, you couldn't have had as much depletion.

Q. And your accumulated depletion would have been different in your Exhibit 274?

A. I would have had less accumulated depletion.

Q. Yes. How much less?

A. I haven't figured that out.

Q. Oh, you haven't? This depletion study in connection with leaseholds as set forth in both Exhibits 272 and 274, the rate of withdrawals would have a very distinct bearing upon the life of the field or the life of the—the producing life of the acreage of Canadian River Gas Company?

A. If you didn't withdraw so much gas—

Q. It would last longer?

A. The whole field would last longer.

Q. That is right. Now, these units of property that you set forth in Exhibit 274 that differs from those in Exhibit 272, how were you able to arrive at your per cent condition of those units of property which do not in fact exist?

A. They are such a small part of the property that they wouldn't affect the overall conditions we have used.

Q. They would not?

A. No.

Q. So you just assumed the same per cent condition would obtain there as did in Exhibit 272, although the units of property don't exist and you couldn't apply your method of physical inspection?

A. The majority of the units do. It is just a slight change in the property which wouldn't affect the overall condition enough to make any adjustment.

Q. But you were not able in connection with the construction of Exhibit No. 274 in determining your accumulated depreciation on any of these units of property to actually inspect the property?

A. To actually inspect it?

Q. To physically inspect it.

A. We did inspect those properties.

Q. These properties applicable to resale gas alone differ from the units on the other, the latter are in actual existence?

A. These are the same properties with an elimination of a few items.

Q. Which items?

A. There were some wells that were eliminated and

maybe a small meter station and maybe one small well line. The difference between the two, from $10,141,515 total for resale alone is $10,042,308, so the percentage change there is negligible.

Q. This Exhibit No. 274 reflecting your computation of accumulated depreciation and depletion of production and gathering system facilities is limited to resale gas alone and is not applicable to any operating conditions of the Canadian River Gas Company?

A. Not applicable to operating—

Q. Not applicable to any operating conditions of the Canadian River Gas Company?

A. It is the same property except for those items that I said were not needed for resale.

Q. But it contemplates an assumed limited operating condition of the property?

A. It contemplates what property would have been required for resale gas alone.

Q. Which has not taken place in fact?

A. No, they are still selling direct sale gas.

Q. They haven't at any time in the past limited the use of the facilities to that purpose?

A. No, sir.

Q. As far as you know they don't contemplate limiting it in that fashion?

A. Not as far as I know.

Q. It is being used and has always been used for resale as well as all sale?

A. The entire properties have been. This part is the amount that would be required for just resale alone.

Q. But these facilities have never been limited to resale gas operations alone?

A. The entire properties haven't, no.

Mr. Lange: No further questions on that exhibit.

Redirect Examination.

By Mr. Dougherty:

Q. Mr. Roberts, are you familiar with the quantity of direct sale gas the Colorado Interstate sells a year?

A. I have seen the figures but I am not good in remembering figures.

Q. It would be an easy computation to take that quantity and subtract each year from the total field withdrawals and

determine what, if any, variations in your 36 per cent would result, would it not?

A. Yes, sir.

Q. And assuming for the moment the amount sold each year to the direct sale customers was about 10 billion feet with an average of around 600 billion feet a year sold, or total field withdrawals. That is around 600 billion Mcf. per year. Now, if you had 10 billion off that, could you tell me at about what fraction or percentage that might make in each year?

A. It would be under two per cent; a little over one per cent.

Q. That is over the whole period?

A. Over the whole period, yes.

Q. It would be somewhere above 34 per cent and under 36 per cent?

A. That should be applied, I believe, against the 36.

Q. And—I see what you mean. And subject to your computation—

A. It would be one per cent of 36 per cent.

Q. Subject to your computation as to what it would be, this method you have used gives a greater amount of accumulated depletion than if you had made the deduction of the direct sale gas from the total field withdrawals each year?

A. Yes, I believe I have stated that.

Mr. Dougherty: That is all I have.

Mr. Lange: Just one other question.

Have you made any computation to show what accumulated depletion would be as applicable to direct sales alone?

The Witness: No, sir.

Mr. Lange: That is all.

The Trial Examiner: We will stand in recess for five minutes.

(At this point a short recess was taken, after which proceedings were resumed as follows:)

The Trial Examiner: The hearing will be in order.

Mr. Lange: I have just one other question on Exhibit 274.

The Trial Examiner: All right.

Mr. Lange: As I understand it, you pursued in the same fashion the computation of your accumulated depletion and depreciation in constructing Exhibit 274 as you did in constructing Exhibit 272; that is, you applied the same general principles?

The Witness: Yes, sir.

(Witness excused.)

Whereupon—

H. E. Roberts

recalled as a witness by and on behalf of the respondents, having been previously duly sworn, was examined and testified further as follows:

Cross Examination.

By Mr. Lange:

Q. We will take up Exhibit 273. That is the Denver line property of Canadian River Gas Company?

A. Yes.

Q. You have that exhibit before you, Mr. Roberts?

A. I do.

Q. Turn to your Statement 1.

A. Statement 1?

Q. Yes.

A. All right.

Q. Let's first go to your written statement, Page 2, the second paragraph—I mean the paragraph beginning with "Original cost as given by Mr. Lusk in Exhibit No. 267 were first rearranged to separate the general construction costs from the direct account costs as shown on Statement 2." Where do you make that rearrangement in Statement 1?

A. There is a notation over Columns 5, 6, 7, 8, and 9, Deduct General Construction Costs. They were deducted from the original cost of Exhibit 67 which first had been further divided and included with the general construction costs down below.

Q. That is in Statement 2 of the exhibit?

A. Yes.

Q. In other words, the treatment of those items was handled in the same fashion as in Exhibit 272?

A. Yes, sir.

Q. And in that connection you of course separated those general construction costs and set them apart differently from the way they are presently reflected on the company's books?

A. Yes.

Q. In all other respects you proceeded in the same fashion in setting up your accumulated depreciation of the several units of property in this Exhibit 273 as you did in the previous exhibit?

A. That is correct.

Mr. Lange: I think that is all on Exhibit 273.

The Trial Examiner: You have no questions, Mr. Dougherty, on Exhibit 273?

Mr. Dougherty: No.

(Witness excused.)

Whereupon—

H. E. Roberts

recalled as a witness by and one behalf of the respondents, having been previously duly sworn, was examined and testified further as follows:

Mr. Lange: We will proceed with Exhibit 275.

Cross Examination

By Mr. Lange:

Q. That related to the determination of accumulated depreciation applied to the Denver pipe line for resale gas alone?

A. That is correct.

Q. I believe it is in connection with that exhibit that the different units of property are set up by Mr. Rhodes in his Exhibit 98 to distinguish them from units of property actually in the line at present, is that true?

A. I believe that is the exhibit, No. 98.

Q. You referred to it in your written statement?

A. That is right, yes.

Q. Now, then, let's turn to Statement 1, Exhibit 275. Item No. 6, Transmission Line Equipment, Account 226; is the largest item of property that contemplates maintenance?

A. Yes.

Q. Under Mr. Rhodes' classification or distinction of the property to be utilized on a resale plant set up, you would have 20-inch main line in lieu of the present 22-inch main lines, wouldn't you?

A. That is correct.

Q. And your total original cost would differ materially for that item, too?

A. Yes, because there is a reduction in cost.

Q. About $300,000—in Exhibit 273, it is $2,313,572 and in your Statement No. 1 of Exhibit 275 it is $2,002,808.

A. That's right.

Q. I note that in both cases your per cent accumulated depreciation is the same, seven per cent.

A. That's right.

Q. Now, the line contemplated in your Exhibit 275 devoted to resale gas alone would be a 20-inch line that is presently not in existence.

A. It is a line that would have been in existence if they constructed that line for resale gas alone.

Q. And this item on Statement 1, "Transmission Line Equipment," that you have shown to have a seven per cent accumulated depreciation is presently not in existence.

A. We simply reduced the size and assumed that that pipe would be in the same location as this present line; which would have been under the same soil conditions as this same particular line, but would not offer as much surface to those soil conditions as a 22-inch line.

Q. It would be 20 inches in diameter as distinguished from 22 inches?

A. That's right.

Q. So without having had any opportunity to make an inspection of this assumed 20-inch line, you give it the same per cent condition as you did the 22-inch line that is in place?

A. I believe it is a fair assumption that if you had that one pipe line in there that was 20 inches and another in there that was 22 inches, it would be under the same soil conditions, the same kind of pipe, there would be less surface of that pipe exposed to the soil as in the case of the 22-inch. In the case of the 20-inch line there would be less surface exposed to the soil conditions than in the case of the

22-inch line; so we have given it the same accumulated depreciation.

Q. That is purely an assumption. You didn't have an opportunity, or couldn't have had an opportunity to make any calculations on that.

A. We inspected the 22-inch line in the place that the 20-inch line would be, under the same conditions, the same materials, and it seems to me it is a reasonable assumption that the pitting wouldn't have been any more in the 20-inch line than in the 22-inch line.

Q. So in that connection you had to base an assumption on an assumption. First, you had to assume that there would be a 20-inch line in lieu of the 22-inch line and then you had to assume what the per cent condition of the 20-inch line would be if constructed.

A. We were the engineers that designed this line and we came to the conclusion that the 20-inch line would have been built at that time if it were being built for resale gas alone; so it isn't a very far-fetched assumption on the first part, and on the second part it doesn't seem to be a far-fetched assumption because of the fact, as I have stated before, that line would have been placed in the exact same soil, and it would have been of the same material.

Q. And without having had any opportunity to make any actual inspections, you give it the same per cent condition?

A. We gave it the same per cent conditions that we found for the 22-inch pipe that was there in that same location under the same soil conditions.

Q. And I notice that Item 3, Statement 1 of Exhibit 275, "Compressing Station Equipment," that differs materially—well, not very materially, but to some extent, from your Exhibit 273. You have given that the same per cent condition also, haven't you?

A. $34,000 difference there, approximately.

Q. In what respect does that unit differ on your resale gas—what physical difference?

A. I think that there was one 600-horsepower unit as I recall it that was deferred to a later date.

Q. One less unit, isn't there, in place there? You contemplated to have one less unit?

A. Yes.

Q. So the—

A. That is a small unit there, not the 1,000-horsepower unit. It is a 600-horsepower unit.

Q. Did you take into consideration the difference in the volumes of gas that would be compressed in the resale gas alone as distinguished from all gas?

A. I didn't myself make that calculation. I applied it against the calculations that had already been made and the information which Mr. Rhodes gave in his Exhibit 98.

Q. Well, what I was getting at, how do you know that the compressor units that would actually be in operation would be required to compress the same Mcf. of gas for each system?

A. I say, I didn't make that calculation. Mr. Rhodes did.

Q. Mr. Rhodes made that?

A. Yes.

Q. But you related the accumulated depreciation—you had to satisfy yourself on that, didn't you?

A. I applied it against the property. It was practically the same property with the elimination of that one unit.

Q. Did you just take Mr. Rhodes' per cent condition on that particular unit without giving any other consideration at all, and just mathematically calculated that?

A. No. It was $34,000 against $504,000, a difference that would hardly affect the overall condition.

Q. Well, what I want to know is, did you just take Mr. Rhodes' per cent condition and convert it into dollars?

A. I applied the same per cent condition because the difference in the property was so slight and it was going into too fine a detail to try to figure out a fraction of a per cent on the condition of the property.

Q. That was probably in dollars, the cost of the two items, but what consideration did you give to the difference in operating conditions that would obtain?

A. I didn't give any consideration—

Q. Well, didn't that have a very—isn't that a very material matter to take into consideration as to compressor units?

A. In just what respect do you mean?

Q. Well, don't you take into consideration at all the conditions under which compressor units operate in determining the per cent condition or accumulated depreciation in each of those units?

A. We considered that if they were overloaded and

worked under overloaded conditions probably at the time we observed the conditions we would have found more depreciation.

Q. Yes, it is very necessary to determine the character of operation and the size of the load and the rate at which the units are operated to tell what the condition of those units is.

A. You determine that at the time you look at them.

Q. But you didn't have available for your inspection that substitute plant.

A. It takes a wide fluctuation in load, as I say. If the machinery is overloaded and wasn't being taken care of properly, why, that would affect the condition to a certain degree, but ordinarily variable loads would not affect the condition.

Q. You don't know to what extent those units are going to be called upon to deliver under your proposed resale plant?

A. Mr. Rhodes made that calculation and he would assume that they would be under the normal operating conditions.

Q. But you then just again, just took his per cent condition and just by applying simple arithmetic determined what you say is the accumulated depreciation in these units that will be installed in a resale plant?

A. I considered for resale these engines would be operated similar to the way they are operated for the combined gas.

Q. Regardless of the rate of flow of gas or the demand that would be made on these units?

A. I considered that the difference would not be sufficient to make any refinement.

Q. And of course you had no opportunity to make those refinements?

A. Well, Mr. Rhodes determined what units would be required and he wouldn't have had—he would have put in sufficient units to handle the load.

Q. And in the construction of this exhibit, again, you applied the same methods and principles as you did in the previous exhibits in computing your depreciation?

A. Yes, sir.

Mr. Lange: I believe that is all.

Redirect Examination

By Mr. Dougherty:

Q. Mr. Roberts, there are some blanks that ought to be filled in on the bottom of the schedules referring to other exhibits which I don't think we have done yet. Turn to Exhibit 273, Statement 1, Note (B). There is a blank there. The statement says "As shown on Statement No. 3, Exhibit No. blank relating to depreciation and depletion of original cost." What number should be in there?

A. 272.

Q. 272?

A. Yes.

Q. And then on Statement 2, also, Note (E).

A. Well, will you refer again to that Exhibit 273? I don't see that. Where is that shown?

Q. On Statement 1, at the bottom of Statement 1, Exhibit 273, Note (B) at the bottom of the page, Statement 1.

A. Yes, that is correct, referring to Statement 3, Exhibit 272.

Q. At the bottom of the page of the same exhibit, in Statement No. 2, Note (E), what should go in there? What other exhibit does that refer to? Is that Exhibit 272 also?

A. Yes, Exhibit 272.

Q. Now, then, Exhibit 274, on Statement 1, there is a Note (B) at the bottom that refers to general property also.

A. That refers to Exhibit 272 also.

Q. And then also on Statement No. 2, Note (C), that refers to general property also.

A. Yes, that's Exhibit 272.

Q. And then on Exhibit 275, Statement No. 1, you again have a reference to general property in your Note (B).

A. That refers to Exhibit 272 also.

Q. And then on Statement No. 2, Note (E), at the bottom, should that also be 272?

A. That also refers to the same exhibit, 272.

Mr. Dougherty: If the reporter could, Mr. Examiner, make those notations in the exhibits—

The Trial Examiner: Yes, we'll have them make the insertions in the official copy.

Mr. Dougherty: I had no questions on that exhibit.

Mr. Lange: We'll take up Exhibit 283 of Mr. Roberts. It refers to the Denver line properties of Colorado Interstate Gas Company.

(Witness excused.)

H. E. Roberts

recalled as a witness by and on behalf of the respondents, having been previously duly sworn, was examined and testified further as follows:

Cross Examination

By Mr. Lange:

Q. Exhibit 283 refers to the Denver pipe line properties of Colorado Interstate Gas Company, is that correct?

A. Yes.

Q. You again proceeded in the same fashion as you did in constructing the previously named exhibits?

A. I did.

Q. Now, in connection with the construction of this exhibit I find that during the year 1939 I have a notation as to at least two retirements that were made. I wish you would make a note of that and let me know whether my memo is accurate.

A. All right.

Q. The voucher reference is No. M-36.

A. What year? 1939?

Q. Yes, 1939.

A. All right.

Q. The account numbers covered in that one voucher, are 220-D, 226-D, 222-M, and 225-M. The units of property are the transmission lines and measuring stations in connection with the Littleton lateral and the Santa Fe lateral. The Littleton lateral shows a cost retired of $5,161.89, no salvage: the Santa Fe lateral shows the cost retired at $17,981.70, no salvage.

I find that in both instances those units of property were given a 95 per cent condition in Mr. Rhodes' estimate.

A. Yes.

Q. Now, what I wanted you particularly to make a note of was whether the figures I gave you were correct.

A. Do you want me to find out whether those figures are correct?

Q. All items I gave you, whether I have related the particular units of property to Mr. Rhodes' account number with those percentages of condition as he gave it, yes.

A. I have explained before that the condition we gave represented the average of those accounts and as he set the condition opposite them.

Q. You, of course, made no investigation or gave no consideration to retirements that were made by Colorado Interstate Gas Company during the year 1939?

A. Those particular retirements were handled as retirements of property sold when we adjusted our valuation from 1938 to June 30, 1940. Those properties were sold and we removed them from our reproduction cost inventory.

Q. You removed them from your 1938 inventory?

A. Yes, sir.

Q. How do you know they were sold, Mr. Roberts?

A. I saw the sales agreement, I believe, on the Littleton lateral: One of the men went into the field when the Santa Fe lateral was sold.

Q. According to my memo there is no salvage value on either one of the properties.

A. There wouldn't be if they sold them.

Q. Wouldn't there be any record there as to the amount of salvage if there was a sale made and funds realized for the sale?

A. I didn't quite understand you.

Q. Wouldn't there be any salvage indicated on that voucher at all?

A. They got so much money for the property if they sold it.

Q. How did you determine that the two properties were sold at any particular price?

A. I didn't investigate—

Q. Or at any price.

A. I believe I saw something having to do with the Littleton sale, but I was advised by the company—at least the representative I sent out here was advised by the company that the lines had been sold and we removed them from the inventory when we adjusted from December 1938 to June 30, 1940.

Q. Well, at the end of 1938 they were still in the property, weren't they?

A. They were at that time?

Q. Your inventory as of December 31, 1938 would include them?

A. It would.

Q. You say it is your understanding that they were sold, either one or both?

A. Both were sold.

Q. Will you find out whether that information you have is correct or not; if so, for what they sold?

A. At what price they were sold?

Q. Yes.

A. I guess I can determine that.

Q. I see there is another item of retirement during 1939, voucher reference K-29-8, Account No. 224-C, Compressor Station Equipment, four water wells, 1, 2, 5, and 6, that were retired. The cost of them retired is $11,731.19.

A. As I recall it, those were wells not included in our valuation. I can check that.

Q. I see there is no salvage indicated there, either. That unit of property is given a per cent condition of 88 per cent in Mr. Rhodes' estimate, is it not?

A. I believe you are mistaken but I will check it. As I remember it, we did not include those wells in our evaluation.

Q. You did not?

A. As I recall it we did not.

Q. As of December 31, 1938?

A. That is correct.

Q. Will you make a note of those wells?

A. Yes, I have a note of it.

Q. Under that same voucher No. K-29-25, under "Compressor Station Equipment at River Dam," there is $5,972.83.

A How much?

Q. $5,972.83.

A. That was another item we didn't have in the valuation.

Q. There was no salvage indicated in that unit of property under that account number given an 88 per cent condition in Mr. Rhode's testimony?

A. I believe you are mistaken, as we did not include that dam. I will check on it, though. Maybe I can check it right here.

Q. Please do.

A. That dam was at Canon, was it not? Wasn't it at the Canon water pumping station?

Q. I don't have that in this memorandum.

A. It is the Canon water pumping station we included in Exhibit 70. If you will leaf through here you will find there is no dam included.

Q. What exhibit are you referring to—Exhibit 68?

A. Exhibit 70.

Q. What page?

A. Page 222.

Q. Those two items weren't considered in connection with the preparation of the estimate?

A. They were not included in Exhibit 70.

Q. You will make a check and determine with reference to the other two items?

A. Relative to those wells?

Q. No, the Littleton and Santa Fe lateral.

A. Yes, I will check them. We have Well No. 3, Well No. 4—we didn't have the other wells. I will check into the Littleton situation and find the information on it.

Q. Find the information, please, on the Littleton and Santa Fe lateral.

A. Yes.

Q. In this exhibit as stated by you in your testimony, or, rather, in your written statement in the exhibit, you proceeded in the same fashion as you did in previous ones?

A. That is correct.

Q. In connection with your computation of the accumulated depreciation as set forth in Statement 1 and as referred to on Page 2 of the written statement you recorded the same treatment and proceeded in the same fashion in setting forth those general construction costs upon which you then computed the accumulated depreciation?

A. Yes, it was done the same way.

Q. Then in computing the accumulated depreciation on those general construction costs as set forth in your Statement 1, Line 15, you again assumed that one-half of the general construction cost did not depreciate?

A. Yes.

Mr. Lange: I believe that's all on that exhibit.

Mr. Dougherty: I have no questions.

Mr. Lange: We'll take up Exhibit 284, Mr. Roberts.

The Witness: I have it here.

By Mr. Lange:

Q. That relates to resale gas line of Colorado Interstate Gas Company?

A. That's correct.

Q. Now, in connection with the construction of such a line devoted to resale gas or limited to resale gas alone, there are certain differences in construction as well as units of property that would be made as set forth in Mr. Rhodes' Exhibit 98?

A. That's correct.

Q. And the largest change that would take place, of course, particularly in units of property as well as dollars, would be the transmission line equipment, item 5, of statement 1?

A. That is right.

Q. Now, in connection with this assumed resale line contemplated under your Exhibit 284, you would have a 20-inch main instead of a 22-inch?

A. Part of the line would be reduced from 22 inches to 20 inches and the remainder would still stay at 20 inches.

Q. Now, I note a 5-per cent accumulated depreciation applicable in your Exhibit 284 for the 20-inch main transmission line and that is the same per centage that you relate to acumulated depreciation in your Exhibit 283 of the 22-inch line.

A. That is correct.

Q. Is this just a mathematical computation of Mr. Rhodes per cent condition?

A. No. Mr. Rhodes estimated what size line would have been required for resale gas alone and this pipe line would have gone in the same locations as the 22-inch; would have been under the same soil conditions as the 22-inch, and there would have been less surface exposed to the elements, and the pipe would be the same kind of pipe, and therefore I assumed that the depreciation as applied to the one would apply to the other.

Q. So you proceeded in the same fashion, then, as you did on the resale line of Canadian River Gas Company?

A. That is correct.

Q. And in this instance again, this assumed 20-inch line, of course, does not in fact exist?

A. Well, part of the 20-inch is the same as the 22-inch —I mean of the gas for resale alone there would be required the same 20-inch line as there now is, but the 22-inch would be reduced in size.

Q. That's what I mean. The present 22-inch line would be substituted by a 20-inch line.

A. That's right.

Q. And that assumed substitution of the 20-inch line does not in fact exist?

A. No, that is a 22-inch line at the present time.

Q. I note that there would be no difference in compressor units at all.

A. No other units would be required for resale according to the estimate that Mr. Rhodes made.

Q. You contemplate the exact same compressor units for both lines?

A. I believe that that must be right. They are both the same figures.

Q. Would they be used in each instance; that is, in connection with all sales as distinguished from resale gas alone in the same manner?

A. They would be used for the same purpose. More gas would go through the compressors if you had the combined sales than there would if you had just the one.

Q. Well, in determining this per cent condition on compressor station equipment, Exhibit 284, did you give any consideration to the difference in volumes of gas and the rate at which these compressor units would be required to function or operate, in one instance, as compared with the other?

A. No. There might have been some increase in per cent condition if they had been pretty well overloaded for the combined and for the resale they weren't, but that would be a refinement that would be such a small percentage that we did not make any increase in our per cent condition.

Q. Did you attempt to ascertain what the difference in volumes of gas would be?

A. Mr. Rhodes did that.

Q. Oh, he did. You just took his figures, then, after he had arrived at the particular conclusions made?

A. I knew that if you had the same units and had less gas, you certainly wouldn't be using the units harder than you would before.

Q. Well, did you have before you any figures estimating the difference in volumes of gas?

A. Well, we know that the combined gas is more than the gas for resale alone.

Q. You mean the present combined volumes of gas that you have actual records of?

A. Yes.

Q. But you were setting up an assumed resale gas line alone, weren't you?

A. Yes.

Q. And you didn't make any estimate as to the volumes of gas that would be required or that there would be a demand for, or the peak load of such resale plant, did you?

A. No, sir. Mr. Rhodes took that into his calculation when he figured the property would be needed.

Q. And he did all of that himself? You just took his figures, then?

A. Well, I knew that the compressors wouldn't have to pump as much gas because there would be less gas involved on resale gas alone than there would be for the combined.

Q. That's it, and the volumes of gas that a compressor unit is required to handle or the peak load conditions of the line, have a very material bearing on what the condition or the per cent condition of the compressor unit handling such gas is, isn't that true?

A. I have stated before that if it has been overloaded for long extended periods there is liable to be more depreciation, but for ordinary operations any difference in condition is so slight that it could hardly be determined.

Q. But you did know that the demands that would be made upon the compressor units for resale plant alone would be different than those that would be made upon these particular units for all sale gas?

A. I assumed that the difference would be so slight that it wouldn't affect the condition as a whole.

Q. It would not?

A. No.

Q. And for that reason you just gave them the same per cent depreciation?

A. They are the same items. They are the same compressors and they would be used practically the same way.

Q. And of course you couldn't have had an opportunity to have any record of performance under the assumed conditions. That would be, of course, impossible.

A. I could have estimated what it would have been if I wanted to go into the condition of those engines. I didn't do that, however.

Q. Knowing there would be a difference, you didn't think it was of sufficient amount to justify making any change in your per cent of accumulated depreciation applicable?

A. That's correct.

Q. And is that the approach you had to any of the other units of property that differed from the all sale gas properties of the Colorado-Interstate Gas Company?

A. In most cases we found that the condition of these remaining items fell in pretty well with the average and there weren't any items of 50 per cent and others with 90 per cent there. They generally fell pretty close to the average, so the elimination of an item here and there would not affect the condition, and the other amounts in here are small compared with the total, so we applied the same per cent condition to those properties as we had applied in Exhibit No. 283.

Q. Then in all other respects you pursued the same methods and applied the same principles in the construction of Exhibit 284 as you did in previous exhibits?

A. That's right.

* * * * *

Additional cross-examination of Witness Roberts appears under title 27 supra.

Depletion, as used in this exhibit as applied against wells, for instance, is based upon the reserves at the time the wells were drilled compared with the reserves at the time the depletion was determined. (Vol. XCVII, p. 15060.) These reserve figures and the figures covering gas withdrawn are covered by Exhibits 206 and 207, Exhibit 206 being Mr. Peterson's exhibit on gas withdrawn, and Exhibit 207 being Mr. Thompson's exhibit on gas reserves estimated recoverable, at 50 pounds gauge. Mr. Roberts ascertained how much gas was withdrawn in a year as compared with the

gas at the start of that year and applied that factor against the investment of leaseholds in that particular year. (Vol. XCVII, p. 15061.)

This Exhibit 272 does not purport to cover amortization. (Vol. XCVII, p. 15066.) Depletion and depreciation are figured differently. The depreciation determined from observation is an accumulated depreciation showing the condition of the property at the time of the inspection and is an average depreciation for all the properties. (Vol. XCVII, pp. 15069, et seq.)

In depreciating the physical properties he did not take into consideration the life of the gas supply but he found the condition of the property from a physical inspection at a particular date. (Vol. XCVII, pp. 15084, et seq.) The determination of accumulated depreciation is not based upon possibilities of retirement of any particular piece of property, but is the average weighted condition of all the property inspected. (Vol. XCVIII, pp. 15085, et seq.)

Gas well construction was depleted rather than depreciated on the same theory as leaseholds because it was impossible to inspect the insides of the gas wells to determine actual physical condition. (Vol. XCVII, pp. 15087, et seq.)

Mr. Roberts was not interested in the method in which the company may have set up depreciation or depletion on its books, as he used what he considered proper and substantial methods. (Vol. XCVII, pp. 15091, et seq.)

In concluding his testimony upon redirect examination Mr. Roberts stated that the percentage of depreciation shown, for instance, on field line equipment is an overall percentage for the whole field pipe line of Canadian and the percentage figure given is not with reference to any particular section or any particular line, but is weighted percentage applicable to the account as a whole. (Vol. XCVIII, pp. 15218, et seq.) Some pipe might be in only a 70% condition and others might be in a 98% condition. His inspection was to determine where between zero and 100% the depreciation or condition of the property existed, and what he did in this case was by observation to determine that the relationship between zero and 100% was 7% for depreciation overall. (Vol. XCVIII, p. 15219). When the inspections of the Canadian pipe line were made the engineers of the FPC

were present and made observations of their own. (Vol. XCVIII, p. 15220.) When the depreciation of the physical condition is determined, it is then necessary to apply the percentage of depreciation to a dollar figure in order to determine the amount of depreciation in dollars. This has been done by applying the percentage of depreciation and depletion, determined as above, to original cost adjusted, as shown by Statement No. 1 in Exhibit 272. (Vol. XCVIII, p. 15221, et seq.)

Further cross-examination of MR. ROBERTS is abstracted under title 27 supra.

Accumulated Depreciation and Depletion And Its Application to the Equivalent Original Cost of the Producing and Gathering Facilities for All Gas, Except Colorado Interstate's Direct Sale Gas, as of December 31, 1938.

For the Canadian there was introduced and received in evidence (Vol. XCVIII, p. 15279) through the witness, H. E. Roberts, Exhibit 274 captioned as above. This exhibit is prefaced by Mr. Roberts' written statement appearing in the record. (Vol. LXXXXIV, pp. 14434, et seq.)

As explained by Mr. Roberts in his statement, this exhibit covering the subject shown in the heading of this subdivision shows the depreciation and depletion accumulated at December 31, 1938, in the producing and gathering facilities required for all gas, except Colorado Interstate's direct sale gas on the Denver line, as testified to by Mr. Watson and shown in Exhibit No. 121 and as applied to the equivalent original cost of such production and the gathering facilities as shown by Lusk's Exhibit No. 193. The accumulated depreciation and depletion in the production and gathering facilities as of December 31, are shown in Mr. Roberts' Exhibit No. 272. The same percentages of accumulated depreciation and depletion as determined in Exhibit No. 272 have been used in this Exhibit 274.

Further testifying on cross-examination concerning Exhibit No. 274 (Vol. XCVIII, pp. 15241, et seq.) Mr. Roberts reiterated the statements made in his preface to the exhibit, and further testified that no change had been made in the

figures applicable to leaseholds because in his opinion all of the leaseholds would be necessary for the resale gas alone. (Vol. XCVIII, p. 15244.)

Statement No. 1 in Exhibit 274 summarizing the accumulated depreciation and depletion covered by the exhibit is as follows:

Canadian River Gas Company — Statement No. 1

Accumulated Depreciation and Depletion and Its Application to the Equivalent Original Cost of Production and Gathering System Facilities for Resale Gas Alone, as of December 31, 1938.

Summary by Accounts

Item No. (1)	Account No. Company (2)	Description (3)	Original Cost (A) (4)	Accumulated Depreciation and Depletion Per Cent (5)	Accumulated Depreciation and Depletion Amount (6)
		Production System			
1.	205	Leaseholds	$ 5,075,906	36%	$ 1,827,326
2.	211	Gas Well Construction	2,126,986	31	659,366
3.	212	Gas Well Equipment	906,529	31	281,024
4.	209	Field Measuring Station Structures	8,315	17	1,414
5.	215	Field Measuring Station Equipment	46,103	11	5,071
6.	216	Drilling and Cleaning Equipment	24,244	....	....
7.	218	Field Measuring Station Land	100	....	....
8.		Total	$ 8,188,183		$ 2,774,201
9.		General Property (Allocated) (B)	56,273	25	14,169
10.		Total Production System	$ 8,244,456		$ 2,788,370
		Gathering System			
11.	206	Rights of Way	$ 13,485	....	....
12.	213	Field Line Construction	280,540	7	$ 19,638
13.	214	Field Line Equipment	860,376	7	60,226
14.	221	Field Compressor Station Structures	2,969	18	534
15.	224	Field Compressor Station Equipment	13,779	16	2,205
16.		Total	$ 1,171,149		$ 82,603
17.		General Property (Allocated) (B)	44,781	22	9,855
18.		Total Gathering System	$ 1,215,930		$ 92,458
19.		Total Production and Gathering Systems	$ 9,460,386		$ 2,880,828
		General Construction Costs			
20.		Applicable to Production and Gathering Systems	581,922		159,813
21.		Total Original Cost of Production and Gathering Systems	$10,042,308		$ 3,040,641

Notes: (A) As shown in Exhibit No. 193 adjusted as shown on Statement No. 2 attached.

(B) As shown on Statement No. 3 of Exhibit No. 272 relating to Depreciation and Depletion of Original Cost.

With further reference to this exhibit Mr. Roberts testified that he had depleted the leaseholds in the same fashion and at the same rate as in Exhibit 272. (Vol. XCVIII, p. 15245.) It will be noted that the leaseholds are depleted on Statement No. 1 at a 36% rate. Upon request (Vol. C, pp. 14467-15470) Mr. Roberts had caused a computation to be made based upon an elimination of the quantiies of gas sold to industrial customers described as direct sale gas. He stated that the 36% depletion shown in Statement No. 1, Exhibit 272, really should be 36.04% but was rounded out in this exhibit to 36%. The new calculation of leasehold depletion with the direct sale gas eliminated gave 35.62% which was also rounded out to 36% since the estimate is based upon an estimate of reserves and he did not feel it could be brought down to a fraction of a per cent. Mr. Roberts also stated as to the 31% depreciation shown in Exhibit 272 applicable to gas well construction and gas well equipment the absolute accurate figures on this were 31.19% which was rounded out to the nearest per cent, namely, 31%, but that a new calculation based upon the elimination of the direct sale gas shows 30.82% which rounded out to the nearest per cent, still gives the 31%.

Further cross-examination of Mr. Roberts appears under title 27 supra.

Accumulated Depreciation and Its Application to Original Cost of Canadian's Portion of the Denver Line as of December 31, 1938.

The accumulated or actual or observed depreciation existing in this property, as distinguished from the book reserves, was determined by Witness Rhodes in Exhibit 68, pages 35 and 36, abstracted under Title 23. Witness Roberts, whose identity and qualifications have already been stated, in Exhibit 273 adopted and applied such observed depreciation to the original cost as of December 31, 1938, as determined in Exhibit 67, Witness Lusk, abstracted supra. The results are shown in Statement 1 of Exhibit 273, as follows:

Canadian River Gas Company

Accumulated Depreciation of the Original Cost of the Physical Properties of the Denver Pipe Line as of December 31, 1938

Summary by Accounts

Item No. (1)	Account No. Company (3)	Description (4)	Original Cost (A) (5)	Accumulated Depreciation Per Cent (6)	Accumulated Depreciation Amount (7)
	Transmission System				
1.	218	Compressing Station Land	$ 1,516	....	....
2.	221	Compressing Station Structures	102,172	10%	$ 10,217
3.	224	Compressing Station Equipment	504,275	17	85,727
4.	218	Transmission System Land	1,021	....	....
5.	220	Transmission System Rights of Way	35,430	....	....
6.	226	Transmission Line Equipment	2,313,572	7	161,950
7.	223	Other Transmission System Structures	6,188	19	1,176
8.	227	Other Transmission System Equipment	34,775	18	6,260
9.	218	Measuring Station Land	404	....	....
10.	222	Measuring Station Structures	5,602	11	616
11.	225	Measuring Station Equipment	14,575	11	1,603
12.	900	Gasoline Plant Land	615	....	....
13.	902	Gasoline Line Rights of Way	236	....	....

14.	903;906	Gasoline Plant Structures	49,352	15	7,403
15.	904;905	Gasoline Plant Equipment	282,701	27	76,329
16.	255	Telephone System Equipment	74,508	16	11,441
17.	255	Telephone System Rights of Way	12,508		....
18.		Total	$ 3,435,450		$362,722
19.		General Property (Allocated) (B)	170,206		36,080
20.		Total Transmission System	$ 3,605,656		$398,802
		General Construction Costs			
21.		Applicable to Transmission System	395,255		....
22.		Applicable to General Property	11,469		....
23.		Total	$ 406,724		$ 22,493
24.		Total Original Cost	$ 4,012,380		$421,295

Notes: (A) As shown on Exhibit No. 67 adjusted as shown on Statement No. 2 attached.

(B) As shown on Statement No. 3, Exhibit No. 272 relating to Depreciation and Depletion of Original Cost.

Accumulated Depreciation and Its Application to Equivalent Original Cost of Canadian's Portion of a Denver Line for All Gas, Except Colorado Interstate's Direct Sale Gas.

In Exhibit 275 Witness Roberts, following precisely the same method as described in connection with Exhibit 273 supra, applied the observed depreciation as of December 31, 1938, to the equivalent original cost of Canadian's portion of the Denver line, as shown in Exhibit 134, Witness Lusk abstracted supra. The results are shown on Statement 1 attached to Exhibit 275, as follows:

Canadian River Gas Company

Accumulated Depreciation and Its Application to the Equivalent Original Cost of the Physical Properties of "A Denver Pipe Line for Resale Gas Alone" as of December 31, 1938

Summary by Accounts

Item No. (1)	Account No. Company (3)	Description (4)	Original Cost (A) (5)	Accumulated Depreciation Per Cent (6)	Accumulated Depreciation Amount (7)
	Transmission System				
1.	218	Compressing Station Land	$ 1,516	....	....
2.	221	Compressing Station Structures	102,803	10%	$ 10,280
3.	224	Compressing Station Equipment	470,234	17	79,940
4.	218	Transmission System Land	1,021	....	....
5.	220	Transmission System Rights of Way	35,507	....	....
6.	226	Transmission Line Equipment	2,002,808	7	140,197
7.	223	Other Transmission System Structures	6,188	19	1,176
8.	227	Other Transmission System Equipment	34,775	18	6,260
9.	218	Measuring Station Land	404	....	....
10.	222	Measuring Station Structures	5,602	11	616
11.	225	Measuring Station Equipment	14,575	11	1,603
12.	900	Gasoline Plant Land	615	....	....
13.	902	Gasoline Line Rights of Way	236	....	....
14.	903;906	Gasoline Plant Structures	49,352	15	7,403
15.	904;905	Gasoline Plant Equipment	282,701	27	76,329
16.	255	Telephone System Equipment	71,508	16	11,441
17.	255	Telephone System Rights of Way	11,508	....	....
18.		Total	$ 3,090,903		$335,245
19.		General Property (Allocated) (B)	170,206		36,080
20.		Total Transmission System	$ 3,261,109		$371,325
	General Construction Costs				
21.		Applicable to Transmission System	378,318	....	....
22.		Applicable to General Property	11,469	....	....
23.		Total	$ 389,787		$ 22,192
24.		Total Original Cost	$ 3,650,896		$393,517

Notes: (A) As shown on Exhibit No. 134 adjusted as shown on Statement No. 2 attached.

(B) As shown on Statement No. 3 of Exhibit No. 272 Relative to Depreciation and Depletion of the Original Cost of Producing and Gathering Facilities.

Further cross-examination of MR. ROBERTS appears under title 27 supra.

Provision for Depreciation and Depletion and Corresponding Reserves, as Shown by Company Books.

Under Title 27, "Amortization and Depreciation," supra the evidence is abstracted showing the basis upon which both companies in the beginning dealt with the subject of depreciation. Colorado Interstate began to amortize its cost of contracts on the basis of a 20-year project term and Canadian River began to set up a reserve for depletion for its leaseholds and other depletable costs on the same basis.

WITNESS LUSK testified on direct examination: (Vol. XIX, pp. 2618-2619.)

Q. I notice an item of income taxes in this statement. Will you explain how the company might have income subject to income tax under this character of contract?

A. Well, it all came about with the rulings of The Internal Revenue Department that certain depreciation was not allowable. Therefore, the company was assessed amounts of income taxes from approximately 1931 right down to 1939.

Q. That is to say that there is a difference between the amortizations under the contract and the amortizations, broadly speaking, that are allowed by the Bureau of Internal Revenue for income tax purposes?

A. Well, the Bureau of Internal Revenue wouldn't allow amortization of debt to be included in amortization under any other form, under any circumstances.

Q. Did the original contract, Exhibit 16, make any provision for income taxes?

A. No, sir, it specifically exempted all forms of income tax.

Q. When income taxes developed by reason of this difference in amortization, were arrangements then made to include income taxes as a part of the cost of gas?

A. Yes, sir.

Q. And they have been included subsequently?

A. Yes, sir.

MR. LUSK on cross-examination testified: (Vol. XIX, pp. 2640-2644.)

Q. Refering back to your statement with reference to the changes made or recommended by the Internal Revenue Department, what did the Internal Revenue Department have to say with reference to the company's method of setting up depreciation or depletion on its books?

A. Well, the principal objection of the Internal Revenue Department in the early years was the disallowance of the difference between the cost of the leases and the amount that the company had taken as a depletable base.

The Internal Revenue Department also recommended certain changes and they were adopted by the company, adopted in 1931, in which the company accepted depreciation on a 25-year life basis.

Q. And what had the company set up on its books before that time?

A. The company originally started out to depreciate all of its depletable property on a 20-year life basis, five per cent.

Q. And what was the company's reason for setting them up on a 20-year life basis?

A. It was the life of the contract.

Q. That was for the purpose of tieing in with the provision of that contract?

A. That was the original intent, yes, sir.

Q. Then, when the Internal Revenue Department suggested the change did the company set up its depreciation on that basis as recommended by the Internal Revenue Department?

A. They did—unfortunately, they did.

Q. What year was that?

A. About 1931.

Q. 1931?

A. Yes, sir.

Q. Why do you say it was unfortunate that the company had to do it on that basis?

A. I am glad you asked that question, Mr. Lange.

Q. All right.

A. Because that is one—

Q. We want to air the whole thing. Let's get the reason for it.

A. I could never understand why the Canadian River Gas Company accepted the rule of the Internal Revenue Department and attempted to fit those rulings into the corporation accounting. They should be set up following their own practices and thoughts. The Internal Revenue Department is interested in taxes and not in corporation accounting.

Q. Well, but you just said they didn't set that up according to their own plans and thoughts but set it up to be complying with the provision of that contract.

A. No, I didn't.

Q. You say they set it up on a 20-year basis according to the contract?

A. That is correct.

Q. Their opinions or views didn't enter into that after that became fixed?

A. What I am quarreling about is why did they have to accept the Internal Revenue Department's rulings? They could still have gone on a 20-year life basis.

Q. Well, when the Internal Revenue Department made those changes or required those changes to be made, who was in charge of the acounting department of the company at that time?

A. Either—I think it was Mr. Simpson.

Q. Mr. Simpson?

A. Yes, sir.

Q. He is the Mr. Simpson referred to previously in this testimony?

A. Yes, sir.

Q. What was his opinion about it?

A. Why, I imagine that he took the matter up with New York and Amarillo and he was instructed to follow the Internal Revenue Department's ruling.

Commission WITNESS KENNETH L. SMITH testified on cross-examination: (Vol. XLIX, pp. 6792-6797.)

Q. Mr. Smith, I take it that you assume no responsibility for the service life estimates which were furnished by the Bureau of Engineering.

A. As to supporting them, no I do not.

Q. You just accepted them as they gave them to you?

A. I have accepted them and I have no reason to consider them unreasonable to the best of my knowledge.

Q. Well, a matter of determining service life is primarily an eingineering matter rather than an accounting matter.

A. That is true.

Q. It requires knowledge of the type of property through which it is put, the country through which it runs all of those things.

A. Any number of things which, of course, were not a part of my assignment. I merely made that statement to say that I accepted them in good faith and in good confidence as an accountant.

Q. Now, do you have with you or can you furnish us a copy of the service life estimates of various types of property which you used?

A. Service life estimates I think are set forth in my exhibit. Take, for example—turn to Schedule 2 on Page 16 as an example, Line 6, the annual rates are shown—

Q. Well, from that—

A. —that is, the percentages.

Q. That indicates that for main line, the service life is fifty years?

A. That is correct.

Q. Well, what I would like to have is the report and whatever reasons are in the report that support fifty years.

A. Well, in that case I think I will refer that question to counsel.

Mr. Lange: Yes, that will be in a separate tabulation and exhibits supported by the engineer that prepared them. Yes, sir, that will be in detailed form.

By Mr. Dougherty:

Q. I take it that you are applying this at the same rate each year, that is, on a straight line basis, two per cent each year?

A. Yes, that is correct.

Q. What is your definition of depreciation?

A. Well, I have adhered to the definition in the Uniform System of Accounts of the Commission for natural gas companies. It appears on Page 4.

Q. Yes. That is No. 14?

A. No. 14.

Q. Will you read that, please?

A. "Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the use of natural gas companies, the exhaustion of natural resources."

Q. Did you or do you know whether in the determination of the service life by the engineering bureau that that last phrase was considered; that is, the exhaustion of natural resources?

A. I so understand that that was given consideration but I do not know the particulars.

Q. Well, the reason I ask that, the word "service life" ordinarily implies the physical life of the particular property and what I was interested in is whether this estimate of service life was made without consideration of the exhaustion of natural resources which move through the line.

A. No, it is my understanding that the Bureau of Engineering did give that consideration but, as I say, they made the determination. I did not and therefore I do not know the particulars except that I know they have given it consideration.

Q. Well, I take it what you have done is really take their percentages or percentages that represent the service life and then applied those retroactively to the various classes of physical property of the company year by year and in that way arrived at the accrued depreciation as of December 31, 1939.

A. I don't know the significance of your word "retroactively," but I did employ those percentages from the beginning or the inception of the company.

Q. The word as I understand it and I used it to mean, applying to a period prior to the date you made your computations.

A. Well, I applied these service life estimates or percentages derived therefrom commencing as of the inception of the company.

Q. And the date when you did make that computation was when?

A. Well, these computations were, of course, made in the summer and fall of 1940.

Q. You probably learned that the rates of depreciation which the company had actually been accruing on its books had been accepted by the Internal Revenue Bureau each year as the Federal income tax settlement was made for such year?

A. Well, I have no knowledge of any pending litigation or discrepancy between the company's accounts as kept by its books and the settlements for income tax purposes. It is my general understanding that they were using a basis for depreciation which was in conformity with requirements of the Bureau of Internal Revenue.

Q. Did you make any investigation of the records of the Bureau of Internal Revenue on this company to obtain what information you could with respect to the question of depreciation?

A. No, I didn't go into detail on it. My study is predicated upon the service life estimates furnished by the Bureau of Engineering and as to what extent they studied that situation I don't know.

Q. That is, if any inquiry were made it probably would have been by them rather than by you?

A. It seems to me that getting to the heart of the thing, it would be related to the service life estimates.

Q. So that your exhibit primarily is a series of computations that change or depend upon the basic data furnished you by the Bureau of Engineering. I am leaving out of that now the question of the base against which you applied; that is, the plant account.

A. Yes. The result of my exhibit here would be dependent as one of the significant factors in the computation upon the service life estimates furnished by the Bureau of Engineering.

* * * * *

Mr. Smith further testified: (Vol. XLIX; p. 6806.)

Q. Well, you are recommending it now, I take it. You are recommending it to the Commission for the purpose of

assisting the Commission in determining how much depreciation should be included in the rate structure?

A. Yes. I am showing here a result which shows what I consider to be the proper provisions chargeable to expense and as a result of that same computation the proper accrued depreciation as of December 31, 1939.

* * * * *

Mr. Smith further testified: (Vol. XLIX, pp. 6821-6830.)

Q. I will ask you at this time whether in connection with your accounting work in the matter of Canadian River Gas Company you have prepared an exhibit entitled "Annual and Accrued Depletion and Depreciation of Gas Plant Accounts and Examiner's Adjustments"?

A. That exhibit is, generally speaking, my work so far as the annual accrued depreciation is concerned and Mr. Luttring's work so far as annual accrued depletion is concerned.

Q. Oh, yes, I intended to ask you whether some other accountant on the Commission's staff also worked with you in the preparation of this exhibit.

A. Yes.

Q. That is Mr. Carl E. Luttring?

A. Yes, sir, that is correct.

Q. And is this exhibit that I am now handing you the one that was prepared by you and Mr. Luttring?

A. That is correct.

Mr. Lange: Will the reporter please identify it?

The Trial Examiner: It will be marked for identification as Exhibit No. 176.

(Exhibit 176, Witnesses Smith and Luttring, marked for identification.)

By Mr. Lange:

Q. Now, Mr. Smith, did you in connection with the preparation of this exhibit also prepare a written statement summarizing the main portions and pieces of the exhibit?

A. Yes, I have.

Q. Will you please read that into the record?

A. "This report sets forth the annual and accrued de-

pletion and depreciation of the gas plant accounts of Canadian River Gas Company for the years 1928 to 1939, inclusive. By account classification, it shows annual accruals for depletion and depreciation, based on estimated recoverable gas reserves and service life estimates furnished by the Bureau of Engineering of the Federal Power Commission. It also shows original cost of property retired, salvage on retirements, and other credits, as adjusted by this and other Examiners.

"A comparison of the reserves for depletion and for depreciation of gas plant in service, per books, with those reserves as adjusted by the Examiner, is as follows:

Components of Reserve for Depletion 1928-1939

	As Adjusted by Examiner (Schedule No. 1 Column 3)	Per Books (Schedule No. 5)	Difference
Provision for Depletion charged to Expense	$ 283,170.98	$1,541,371.16	$1,258,200.18
Reserves Acquired	66,929.97	66,929.97	—
Retirements			
Original Costs Retired	(283,657.37)	(432,038.49)	(148,381.12)
Salvage	259,523.00	44,625.00	(214,898.00)
Adjustments of Prior Years' Depletion through Surplus		(69,721.49)	(69,721.49)
Profit and Loss on Retirements (net)		337,203.92	337,203.92
Applicable to Gas Plant held for future use	(1,423.16)		1,423.16
Balance in the Reserve, December 31,1939	$ 324,543.42	$1,488,370.07	$1,163,826.65

Components of Reserve for Depletion 1928-1939

	As Adjusted by Examiner (Schedule No. 1) Column 4	Per Books (Schedule No. 7)	Difference
Provision for Depreciation			
Charged to Expense	$1,679,038.38	$3,764,067.58	$2,058,029.20
Charged to Plant Account	8,031.60	8,031.60	—
Reserves acquired	113,205.45	116,738.18	3,532.73
Retirements			
Original costs retired	(732,713.88)	(813,054.40)	(80,340.52)
Salvage	369,833.15	249,138.31	(120,696.84)
Adjustments of Prior Years' Depreciation through surplus		(636,598.22)	(636,598.22)
Profit or Loss on Retirements (net)		267,205.42	267,205.42
Applicable to Gas Plant held for future use	(2,339.96)		2,339.96
Balance in the Reserve, December 31, 1939	$1,435,056.74	$2,955,528.47	$1,520,471.73

"The Examiner's adjustments were effected through the medium of reclassification and adjusting entries, which were made by this Examiner and others. Of these entries, those which relate primarily to depletion and depreciation are given in this report, and are designated by the numbers 400 to 413, inclusive.

"Entries Nos. 400 to 406, inclusive, which were made in connection with the adjustment of annual and accrued depletion were prepared by Mr. Carl E. Luttring, and the other seven were prepared by this Examiner.

"Entries of the '100' and '200' Series which affected this study are contained in the reports on this company entitled 'Income Account and Supplemental Data including Examiner's Reclassifications and Adjustments' and 'Gas Plant Account and Examiner's Adjustments,' respectively.

"The entries are principally of two kinds, those that affect only the reserves for depletion and depreciation and serve only to adjust the amounts of the several elements of the reserves, which entries are denoted by the letter 'R' prefixed to the numeral, and those entries that involve not only the reserve for depletion or depreciation but one or more other accounts as well. The chief purpose of all these entries is to adjust the annual provisions for depletion and depreciation expense and, concurrently, to adjust the reserves for depletion and for depreciation so that those reserves will properly reflect the total depletion and the depreciation *ligitimately* accrued on gas plant.

"The company's reserves for depletion and depreciation and the depletion and depreciation expense accounts have been reclassified and adjusted to correct various errors and to conform the annual and accrued depletion and depreciation to the remaining natural gas reserve estimates and to the service life estimates made by the Federal Power Commission's Bureau of Engineering.

"The natural gas reserve estimate and service life estimates on depreciable property, furnished by the Bureau of Engineering, yield results substantially different from those obtained by the company on its books, whose annual accruals were based principally on the policy of amortizing property within twenty-five years from January 1, 1931. The methods and the results of adjusting the reserves are set forth in considerable detail in the adjusting entries, each of which states specifically the reason and basis for each adjustment.

"Briefly, the facts about the adjustment of the reserve for depletion are these: As of August 1, 1939, the volume of the company's remaining gas reserve was estimated by the Bureau of Engineering as being 3,656,158,000 Mcf. at 14.65 lbs. per square inch absolute pressure; the production of gas from the company's wells on its acreage by periods, from June 1, 1928, the date of the company's inception, to December 31, 1939, was translated to the 14.65 lbs. base; the number of Mcf. produced during the eleven year and two months' period, from June 1, 1928, to August 1, 1939, plus the 3,656,158,000 Mcf. was considered the original volume of gas, so determined; the undepleted cost (cost less

reserve) of leases and gas well intangibles was diminished for each annual period by an amount which bore the same ratio to the total undepleted cost as Mcf. of production in each period bore to the estimated volume in Mcf. of gas reserves at the beginning of each period.

"Depreciation was computed for purposes of adjustment, based on the adjusted balances in each depreciable plant account. In a majority of instances the appropriate annual depreciation rate was applied to the adjusted plant account balance at the beginning of the year. If a substantial item of plant was added during the year, six months' depreciation rate was, as a rule, computed on that item in the year acquired. All minor plant additions and retirements were, for the purpose of this study, ignored for the year in which they occurred. They were, of course, taken into account in succeeding years.

"Following the adjusting entries, at Page 19 of the report, appears Schedule No. 1. This tabulation contains the information described in the first paragraph of this text except that it gives this information by major functional groups of plant rather than by accounts. It shows separately the depletable and depreciable plant in service and shows depreciable plant, subdivided into production, transmission, and general and undistributed plant. Schedule No. 1 is supported by Schedules Nos. 2, 3 and 4, and their subschedules, and they give, by plant account, the same kind of information that appears on Schedule No. 1. Schedule No. 2 shows six subclassifications of production plant; and Schedule No. 4, nine subclassifications of general and undistributed plant. Schedule No. 2 is supported by two subschedules which furnish subclassifications of other field facilities and gasoline plant, and Schedule No. 3 by one subschedule which shows main line and laterals in four subclassifications consisting of one main line and three laterals.

"The information given on the first five lines of Schedules Nos. 1 to 4, inclusive, and their subschedules are explainable as follows:

"Line No. 1, original charges per books, represents the cost of the company's initial construction and acquisitions plus subsequent gross additions, exclusive of construction

work in progress and gas plant adjustments. In most instances, therefore, the amounts on Line No. 1 may be arrived at by adding to the December 31, 1939 balance per books all retirements from the inception of the company to December 31, 1939, exclusive of construction work in progress and gas plant adjustments.

"Line No. 2, adjustments, represents the net adjustments to these plant accounts made by the Examiner who prepared the report entitled "Gas Plant Accounts and Examiner's Adjustments.'

"Line No. 3, is the sum of Lines Nos. 1 and 2 and represents the adjusted total cost subject to depletion and depreciation.

"Line No. 4 represents total retirements from the inception of the company to December 31, 1939, as adjusted.

"Line No. 5 is the difference between Lines No. 3 and 4 and represents the adjusted balance in the plant accounts as at December 31, 1939. The amounts on Line No. 5 agree with the adjusted totals shown in Column 7 of Schedule No. 1 of the report entitled 'Gas Plant Accounts and Examiner's Adjustments.'

"The depreciation rates used in the computations which appear in Schedules 1 to 4, inclusive, are based in general on service life estimates furnished to the Commission's Division of Accounts by its Bureau of Engineering. With respect to a gasoline delivery line to Amarillo and a loading rack at that place, which were retired in 1935, their costs adjusted for salvage were written off or depreciated on the basis of the actual periods of service rather than on the basis of estimates.

"The computation of depreciation on garage equipment, which is included in Schedule No. 4, was handled in a slightly but not essentially different manner than other depreciation computations. The total cost of the autos and trucks purchased in any one year was considered as a group cost, and after that group cost had been fully depreciated, which was usually about four years after the year of purchase, no more depreciation was accrued on that group.

"It will be noted that there were no charges to the re-

serve for depreciation for costs of removal. The company consistently charged these costs to expense. We have made no adjustment for them because they could not be determined without an unjustifiable amount of detailed analyses of payrolls, trucking tickets, and other records. *Approcimately* 75 per cent of retirements were of such a nature that they involved no removal costs.

"Schedules Nos. 5 and 7 are analyses of the reserves for depletion and depreciation for gas plant in service, per books, for the period begun with the inception of the company in 1928, and ended December 31, 1939, and show the debits and credits to the two reserves classified by years in the manner set forth in the tabulations in this text, above.

"Schedules Nos. 6 and 8 are analyses of the reserves for depletion and depreciation for gas plant in service, as adjusted, for the period beginning with the inception of the company in 1928, and ended December 31, 1939.

"The classifications given in those schedules are the same as the major classifications shown in Schedule No. 1 and show the debits and credits to the reserves classified by years in the manner set forth in the tabulations in this text, above. The minor differences in the amounts as classified in the tabulation in the text, above, and as shown by Schedules Nos. 6 and 8, are caused by a variation in classification of $1,423.16 and $2,339.96, which are set forth in the tabulation above, as 'Applicable to Gas Plant held for Future Use.'

"Schedule No. 9 gives the net retirements of plant costs charged to reserve for depreciation, per books, and as adjusted, and provides a recapitulation of the Examiner's reclassification and adjusting entries affecting net retirements. It shows the amount of net retirements by years and supports Line 22, Column 4 of Schedule No. 1.

"Schedule No. 10 sets forth retirements as adjusted, by years and by accounts; it supports Line 4 of Schedule No. 1.

"Schedule No. 11 sets forth salvage on plant retired as adjusted, by years and by accounts; it supports Line 20 of Schedule No. 1."

* * * * * *

MR. SMITH further testified on cross-examination: (Vol. L, pp. 6849-6871.)

Q. Mr. Smith, on Friday you submitted your Exhibit No. 174 which set forth the annual and accrued depreciation of the gas plant accounts of Colorado Interstate Gas Company for the years 1928 to 1939, inclusive.

A. Yes, sir, that is correct.

Q. And at the same time you submitted your Exhibit No. 176 which contains the same information for the same period for Canadian River Gas Company and also accrued depletion with respect to Canadian River Gas Company?

A. Yes, sir.

Q. Now, Mr. Dougherty is about to cross examine you on Exhibit 174, and for the purpose of shortening my cross examination on Exhibit No. 176 which relates to Canadian River Gas Company, I would like to ask you if your answers to his questions relating to the general principles of accounting involved and your accounting methods used would be the same, or will be the same—would be the same with respect to Canadian River Gas Company, and if that is true, and if you will keep that in mind, I do not need to go all over that same field again.

A. I believe that the questions which I answered on Friday afternoon with respect to the principles employed and the engineering support upon which I was relying, the accounting method and the references to the system of accounts of the Federal Power Commission for natural gas companies, I believe that all those answers on Friday would apply equally to Canadian River in so far as the depreciation is concerned.

Q. Yes, I think that is true, also to that part of Canadian River's plant which consists of the transmission line extending from Bivins station to Clayton Junction, your depreciation problem of Canadian River is almost identical with the depreciation problem of Colorado Interstate, is that correct?

A. As far as the accounting principles are concerned. Of course, as to what the engineers found in their study of service lives, I don't know, except that I do know they are adopting similar rates.

Q. Well, suppose you keep that in mind and then when Mr. Dougherty gets through I will ask you a few general questions along that line and we will save time as far as you and I are concerned on Exhibit 176?

Mr. Lange: Right at that point, when Exhibit 176 went on, I did not on Friday afternoon have Mr. Luttring identify his portion of it.

Mr. Spencer: Only as to your portion of it, Mr. Smith.

The Witness: All right. And here is a point, I think:

I don't want to adopt anything I say about Colorado Interstate as applying also to Canadian River until after this cross examination on Colorado Interstate is over. Now, I will consider the adoption at that time if that is all right with you.

Mr. Spencer: That is very satisfactory.

The Witness: As far as my answers from now on are concerned, when Mr. Dougherty is cross examining me, my answers will apply to Colorado Interstate and I will adopt them for Canadian River later on if I can, if that is what you want.

Mr. Spencer: That is very satisfactory. My only point in bringing it up is so that you will have it in mind.

By Mr. Dougherty:

Q. Mr. Smith, did you make some special study of the principles of depreciation accounting as part of the preparation for doing this work in Exhibit 174 and 176?

A. I probably reviewed and intensified my study of the principles of accounting back of depreciation. Naturally I would in order to do a competent job. However, so far as my previous study of the principles of accounting underlying depreciation, that has been going on from time to time over a period of years—a number of years.

Q. There are special principles that apply to depreciation accounting, are there not?

A. I doubt if I would agree with you. I think that the general principles of accounting apply to depreciation the same as any other accounting, whether prepaid insurance or operating expenses or what-not.

Q. In applying those principles, however, it is a fact, isn't it, that many special text books are written on depreciation accounting, particularly to take up the problems that are peculiar to depreciation accounting and the things that you must consider in doing it?

A. There have been several text books written especially on depreciation accounting, that is true, but the underlying principles go right back to fundamental accounting principles.

Q. Well, I would assume that you wouldn't have anything contrary in the depreciation accounting theory that would be contrary to the general principles, but what I am getting at, it is considered as a special problem that must be dealt with specially and a lot of literature has been written on the question of depreciation accounting.

A. There have been special works written on depreciation accounting, that is true.

Q. And isn't it so also that you have to consider many factors in depreciation accounting that you don't have to consider with respect to your income statements, operating expenses, and so forth?

A. Well, I am not sure that I follow that exactly. I think the underlying principle is exactly the same.

Q. Well, you aren't bothered with service lives in operating expenses or income statement accounting, are you?

A. Well, you are involved with something that is very similar in principle when you go to spreading unexpired insurance for example. From an accounting standpoint the principle is practically identical.

Q. Of course, unexpired insurance you definitely know the end date of that.

A. That is the distinguishing feature in the application of the principle, but the principle is the same.

Q. And in service lives, of course, it is not a thing you can fix with mathematical accuracy?

A. Of course, you understand I haven't attempted to fix the service lives. You assume I understand that no one could set them with mathematical accuracy?

Q. That's right.

A. Well, of course, I haven't considered the problems of setting service lives. I think that is the engineering phase of this study, and to what degree the engineer thinks that his method approaches mathematical accuracy, I believe is a question for him to answer.

Q. Now, in depreciation accounting, do you then consider it the duty of an accounting officer of the company in determining what the accounting shall be for depreciation to

accept any information on service lives without any consideration of whether they might be accurate or whether all factors have been considered in arriving at those service lives?

A. I think the accounting officer should satisfy himself that the engineer who prepared the service life estimates is qualified and competent, and if he had any experience, things that he knew of his own knowledge, facts on which to question the engineering estimate, it would probably be his duty to question it, but I do not believe that the accounting officer, unless he happened to be an engineer also, would be qualified nor duty-bound to question it from a technical sense.

Q. I didn't ask you whether he should question it from a technical sense, but what I want to know is, what do you consider the responsibility of an accounting officer in laying down a policy for depreciation accounting with respect to accepting without inquiry what the other officers say with respect to service lives and whether or not you think that such accounting officer would have fulfilled his obligation and responsibilities without making further inquiries as to the method pursued and things that were done.

A. Well, I am not sure but what I have answered your question.

Q. Well, you added the qualifying phrase "technical matters," and there is a lot of practical knowledge brought into use in depreciation accounting, is there not, Mr. Smith?

A. What do you mean by practical knowledge?

Q. Some knowledge of the actual operations of the company, what type of a business it is, what its problems are from an operating standpoint.

A. I don't see that it is essential to the application of the accounting principles, if the engineering factors have been supplied to the accountant.

Q. You think it is purely, then, a theoretical application of accounting principles without the accounting officer himself having any practical knowledge or bringing into play any practical knowledge about the company's business?

A. He doesn't need any practical knowledge as to setting service lives estimates.

Q. I didn't ask you that question. I know you got the service lives from somebody else. I am trying to find out whether you think the accounting officer's work is just that

of a clerk making computations by figures, or whether he must exercise some discretion and have some responsibility about it.

A. He has the responsibility of the matters that are in accounting—

Q. If somebody gives you two per cent times the plant account, that is an easy job. I could do that and the clerk could do that.

A. That is true, but that is not the whole story.

Q. That is what I am trying to find out. What is the whole story? What is it the accounting officer should do in addition to taking the percentage that is given him by the engineer?

A. Well, it is his responsibility to see that after the service life estimates are determined, to see that that is in fact carried out in making the computation side of the entry. Now, as far as accruing depreciation expense and setting up the entries for accruing depreciation expense, applying the percentage is, as you say, somewhat clerical, but there is a lot more to depreciation accounting than merely getting out a calculating machine and applying some percentages.

The depreciable base must be kept in mind and that is the responsibility of an accounting officer and the retirement accounting, the items which are charged against the depreciation reserve in the normal course of business is almost entirely accounting and that is the responsibility of the accounting officer to see that proper charges are made against the reserve from time to time and it is also his responsibility—largely his responsibility, to set up a proper system of control in his accounting organization so that the charges against the reserve for retirement expenses and salvage are properly recorded and so that a proper distinction is drawn between maintenance and depreciation or retirement accounting at all times. Those things are very definitely the responsibility of the accounting officer.

Q. You have left out what you think his responsibility is with respect to the determination of the annual rate of accruals and is the responsibility to the executives of the company for that determination after he has got the service lives, or has he no responsibility for it?

A. Well, that might vary with the expectations of the

officers of the company. I don't know whether I can make a statement about that categorically or not.

Q. I see. It would depend on whether he had assumed responsibility for it, or from an accounting standpoint you have mentioned these other things which the accounting officer is responsible for. You don't think he is to the same extent responsible for the determination for the annual rate which depreciation should be accrued?

A. I don't believe that he is.

Q. Is there any difference in considering depreciation accounting particularly with respect to the annual rate of accrual as between public utility companies and industrial companies?

A. From a strict accounting viewpoint, I can't see that there is.

Q. Well, now, of course, the situation with a utility company is that the annual accrual of depreciation is one of the items that goes into the determination of what the rates to be charged shall be?

A. Speaking now of the annual accrual, now, you mean the depreciation expense account?

Q. That's right.

A. Of course, what goes into computing the rate is a matter that is just outside of the accounting field, I believe. I am not attempting to avoid your question at all, but I will say from the standpoint of accounting principles in order to have the cost of operation for any period that you must include an item of expense for the annual accrual for depreciation.

Q. And in a utility company it is the cost of operation that is determined before the rates are fixed by a regulatory body?

A. Well, I would assume that the regulatory body would want to have that information and would make use of it, but as to how they apply it in making rates, I am not prepared to make a statement.

Q. Now, with an industrial company, their prices are fixed by matters that are determined many times prior to the determination of the depreciation expense, if they have any, isn't that correct? That is, an industrial company or any type of organization or company that does not have its rates subject to regulation fixes its prices without reference

to depreciation expense but it may be in the operating expenses?

A. I am not prepared to say how the prices for industrial concerns are set, but I will say this, that they cannot compute their true cost of operation without including a proper provision for depreciation. That is elementary and fundamental in accounting.

Q. That is true whether they know them in advance or know them after the cost has occurred or before the sale or after the sale is made?

A. Well, it is true as an accounting principle, regardless of anything else, whether they sold a nickel's worth or not.

Q. You are relating this matter of depreciation accounting in your exhibit only to the problem of accounting and without having in mind any bearing that the exhibit might have on the question of fixing rates under investigation by the Commission in this case?

A. I applied the very best accounting principles that I could conceive of and learn about through study and what I have gained from my own experience, so as to come to what I thought not only applied for depreciation but for all of the other elements we put into the income statement, which I supervised the preparation of, so that we have come to what we consider to be as near as it is possible to get the figures for the true cost of gas operations.

Q. You did that just the same as if you had been applying accounting principles to a steel mill or grocery store or any other type of enterprise?

A. The accounting principles are exactly the same whether they are for a steel mill, grocery store, or public utility, or what-not.

Q. And you are not giving any special consideration to the fact that the depreciation expense is one of the important factors in determining reasonableness of rates in a rate case?

A. That hasn't been an integral part of my study as such. The use of my exhibit that might be made in setting rates is something I haven't had a part of and possibly will not have a part in directly

Q. When you as an accounting officer made up your mind about these annual rates of accrual, I suppose you have in mind that if you want to be certain that your reserves will

accrue in the full amount required that there must be an adequate accrual to do that?

A. Will you read the question again, please?

(The question referred to was read by the reporter, as set forth above.)

The Witness: Maybe we can state this another way and shorten it a little bit.

What you mean is that the annual accruals must be of sufficient amount to retire the property at the end of its service life?

Mr. Dougherty: Quite so, yes.

The Witness: Yes, I think that is correct.

By Mr. Dougherty:

Q. If there is any question of doubt as to whether an estimated annual return will accrue depreciation to sufficiently retire the property, is it proper as a matter of conservative accounting practice to lean towards the side of a greater amount of annual accruals rather than a lesser, assuming that you have two figures which you are considering?

A. Well, I don't believe that an accountant has any choice after the service life estimates are figured. After the service life estimates are fixed I can't say that I am going to lop five years off of this and ten years off of that. There wouldn't be any rhyme or reason to that.

Q. Supposing the engineer says that his service life would be between thirty-five and forty years but he couldn't give you any more of an exact figure. What would be your practice?

A. If he said between thirty-five and forty years?

Q. Yes.

A. I would ask him to make up his mind and give me the figures.

Q. Then if there is any question about it he would have to decide whether he would take 35, 36 or 37 years?

A. I think so because I think I would be getting into the field of engineering if I made up his mind for him.

Q. What would you do if you asked two engineers and both of them gave you different answers and both of them were of equal reputation?

A. You are speaking of me now as an accounting officer of a *compny*?

Q. Yes.

A. Of course, I don't think that situation would exist.

Q. You think the fixing of service life is a matter of mathematical calculations, it is as easy as that?

A. I didn't mean that. I mean that I don't know about that because I am not an engineer. Of course, this is a situation I have not dealt with but I just can't conceive of it coming up that two engineers on the staff of a company would come to me with two different answers and want me to use two different bases.

Q. You would just ask one engineer or you would tell them to get together on it?

A. I would want to know all of the facts and circumstances. I don't know. It is a very hard thing to do in answering these hypothetical situations, especially so when it is a little bit more removed from what might happen actually. I would naturally have to come to some result eventually, but I would want to get it from the engineers rather than get into the field of engineering myself and decide their engineering problems for them.

Q. Do you recognize any difference in depreciation accounting as applied to an company which owns a hydro-electric plant or an electric public utility which has an indefinite period of service as a base, and a natural gas company which is dealing in an exhausting asset or resource?

A. The principles are no different. The whole objective is to spread the cost over the service life. Now, as to the factors which enter into the computation of service lives, it looks to me that when the service life is set, naturally those things are taken into consideration in that service life but as far as applying to accounting, I think the application of the accounting principles are exactly the same.

Q. Do you have when you get your service life the element included in there of depreciation which I think is referred to as "functional"?

A. It is my understanding that the engineers have carefully considered and have arrived at conclusions in arriving at functional depreciation. It is not a part of my study.

Q. Well, do you recognize that in a business dealing with an exhausting resource or asset, such as a coal mine

or gold mine or oil well, or natural gas company, that you have a problem of the ending of that operation for reasons other than the mere ending of service life for physical units of property?

A. One in accounting frequently comes into contact with the fact that that probably exists. For example, a coal mining company often pays dividends out of its depletion reserves and I understand that it is legal for it to do that, and you see evidence of those things, but as far as taking those factors into consideration and setting a rate of depreciation that is to be accrued, of course, that is purely an engineering problem.

Q. Assuming that you were the accounting officer for a coal mine and you had the various physical facilities, the tracks, the tipples, and whatever other machinery they use around a coal mine, and the engineer came in and said to you that the service life of that property was fifty years, would you consider it any part of your duty to inquire of him whether or not the economic life of the coal mine would be fifty years, that is, whether the coal mine would last that long?

A. You mean, in other words, if its reserves would be exhausted before that time?

Q. Yes, wouldn't it be a part of the responsibility of the accounting officer to find out whether the reserves would be exhausted before fifty years' time?

A. Of course, he couldn't make that determination upon his own account. You mean he would have to rely upon his expert—

Q. All right, but isn't it part of his duties to make inquiry and consider it, and if not, to have it considered?

A. Of course, as an accounting officer I think his responsibilities would end with the authority and responsibility that had been delegated to him by the management of the company or by the directors in any particular instance.

If the management of the company had instructed the accounting officer to have used the service lives and delegated the responsibility of setting proper service lives forth to the engineers for the coal mining company, I am not so certain but what the accounting officer would have discharged his real responsibility.

Now, if he had any reason to doubt the competency of the

engineers who gave the estimates or felt that it was necessary to inquire into their procedure, I think it would be a responsibility for him to do that because he would want to see some support, some sort of a statement from the engineers as to their methods, but he couldn't pass upon whether that method was technically sound.

Maybe I have gone all around your question and haven't wound up at the exact point you wanted me to, but if this accounting officer had knowledge of the fact and knew it either through reliable information that he had obtained, or otherwise, information upon which he could rely, and he knew the exhaustion of those resources would take place before the service lives set for the physical property, then obviously he would not be using good accounting practice not to go into it further..

Q. My question is this, that the accounting officer is the principal and responsible accounting officer of the company; that he has been told by the president that he can use all of the engineering figures made by the engineers but that he was going to hold you responsible. The next step was that you called in your engineers who gave you a service life. Don't you feel that it is the responsibility of that officer to find out whether the engineers have considered the exhaustion of the coal and what consideration they have given to it even though you don't know a thing about it?

A. Yes, I believe that would certainly be a higher class practice than to ignore or overlook it.

Q. Isn't the first thing an accounting officer would do would be to check with the engineer as to the relationship of his service life to your estimates of the exhaustion of this coal mine? Isn't that one of the first questions you would ask?

A. I think that he would have to recognize that relationship and he ought to be satisfied on that point but he couldn't make the determination.

Q. No, but I say this: Wouldn't he have to say it had been made and given consideration?

A. I believe in order to follow out his responsibility as chief accounting officer on a high plane from a professional and ethical standpoint, he would have to make some investigation that he would have to rely upon in forming his opinion as to the estimate by technical experts in that field.

Q. Now, do you recognize in such a case as a coal mine that by the time that the exhaustions of the coal had taken place there should have been accrued a depreciation reserve sufficient to retire all of the physical property used in connection with that coal mine less salvage?

A. That is correct.

Let me restate it to you to make sure that we are on the right track.

Q. Surely.

A. By the time the exhaustion of the mineral deposit is made there must also be enough money in the depreciation reserve to retire the equipment less salvage, less net salvage?

Q. That is right. That is my problem.

A. Yes, that is exactly right and that is in accordance with sound and accepted accounting practices.

Q. That would be true even if the physical service life of the equipment were a greater number of years than the period of life of the mineral deposits, that is, to put it specifically, let's assume that the physical service life of the equipment was fifty years for each piece of equipment and that the exhaustion of the resources would take place in forty years; you would have to base your depreciation on forty years rather than on fifty years?

A. Yes, that is correct.

Q. Now, in connection with that problem, do you know whether in this case—that is, the current case at hand—the engineers based their 50-year life of transmission line pipe of Colorado Interstate Gas Company on the physical factors or did they give any consideration to the exhaustion of the source of supply of gas which goes through that line?

A. They, as I understand it, did give consideration to the exhaustion of the source of supply of the gas which moves through that line. I don't know the particulars of that but I do know that it was considered and that the source of supply and the availability studies do have detail from an engineering standpoint in such a way there was no flaw in the service lives they adopted.

That is my understanding of the situation, that is, the understanding upon which I have proceeded.

Q. You say there is no flaw in it; is that your own judgment?

A. No, that is my understanding, that there is no flaw in it.

Q. That would apply with respect to that part of the Canadian River Gas Company's property from Bivins north, the same 50-year life as assigned, because you have used two per cent in the exhibit on transmission line?

A. It seems to me that the situation there is entirely comparable to the main line of the Colorado Interstate Gas Company.

Q. Do you know whether or not the fifty years is the life of the field or is the physical life of the pipe, or is it a composite figure that has been arrived at after giving consideration to both the physical and functional factors as involved in this matter?

A. It is my understanding the physical and functional factors have all been given proper consideration from an engineering standpoint.

Q. I assume that the period of exhaustion of the gas reserves would not be less than fifty years, which is the service life used; that is, isn't that a fair assumption to make?

A. I believe from everything I have said here and the evidence that is in my exhibit, you could fairly conclude that.

* * * * *

Mr. Smith further testified on cross-examination and redirect examination as follows: (Vol. L., pp. 6922-6936.)

Take the Bivins camp, for instance. There you have under "Structures" 2.86 per cent. I think that is on Page 23.

A. Column 10.

Q. Excuse me?

A. That is Column 10 you are referring to?

Q. Yes. Do I understand that that is a composite rate or is that a rate that is applicable to the Bivins camp only?

A. The 2.86 per cent representing 35 years is a composite life, as I understand it. There again the engineering staff is I believe the ones that can give you better information on that than I can.

Q. All right, now, you have a rate of 2.86 per cent on structures relating to the Bivins camp, and you have a rate of 4 per cent applicable to equipment. Am I correct in assuming that the equipment is going to wear out before the structures do, is that right, at this Bivins camp?

A. Well, it would seem that a shorter service life would imply that that equipment would wear out earlier than the structures, other factors being equal.

Q. Yes. that is right.

A. But it doesn't necessarily follow—

Q. Well, wait. We are just on these figures here, on your figures using the four per cent of the equipment, that means the equipment has a service life of twenty-five years and using your figures 2.86 per cent for structures that is approximately thirty-five years life for the structures, is that not so?

A. Yes.

Q. Now, what I want to ask you, at the end of twenty-five years when the equipment is worn out, been fully depreciated, do you have in mind in your study that you have made here that the company shall replace the equipment and put in new equipment to carry that along, to replace that that is worn out?

A. Well, of course, all of the equipment won't wear out in exactly tweny-five years and I don't think a composite rate of four per cent or a composite service life of twenty-five years means that—there is some of that equipment that will wear out and may have already worn out. Some of it might be less than twenty-five years and some of it might be more than twenty-five years. Twenty-five years is the composite life. Now, in treating this as a going concern which will operate so long as a supply of gas is available, I think it does follow that there will be placements of equipment which might have a short service life.

Q. Let me put my question another way: Of what use to the company would the structures be for thirty-five years when the equipment that is in it will be gone in twenty-five years?

A. You are assuming now that there will be no equipment replaced?

Q. I don't know. I am trying to find out what you are assuming in making this study. That's all I'm trying to do here.

A. Well, I have stated my assumption in the previous answer.

Q. Perhaps I didn't understand. Will you repeat to me again—

A. Well, we have assumed throughout this study that

the Canadian River Gas Company will be a continuing enterprise so long as a supply of gas is available.

Q. Will you put right in there which, according to your calculations here, will not be less than how many years?

A. I didn't make those calculations.

Q. Well, the calculations that you use. Perhaps you don't understand me. You do assume here in using 50-year life, for instance, for transmission lines that Canadian River Gas Company will have an available gas supply for not less than fifty years, isn't that correct?

A. Yes.

Q. You so testified this morning I understood.

A. Yes, that is a fact, and I have in effect at least testified that the engineering data will provide a sufficient margin over fifty years.

Q. To give you an average even on the fifty?

A. I don't understand that.

Q. I mean an average by this: Some are going to wear out before fifty years and maybe some will last longer than fifty years. You think that fifty years is adequate for the purpose of this study, taking both the shorter life and the longer life into consideration? That is what I understood from your testimony this morning.

A. I am not sure that I understand whether there is a question pending or whether that is a question.

Q. Well, I have forgotten, so we will withdraw it.

Now, turning to your written statement, Mr. Smith, did I understand it you had nothing to do with the depletion work in connection with this exhibit? That was done by Mr. Luttring?

A. Yes, that is correct. Mr. Luttring has prepared the depletion.

Mr. Lange: Mr. Spencer, are you now referring to Exhibit 176?

Mr. Spencer: Yes.

Mr. Lange: Well, as I stated this morning, there is a certain portion of that that was prepared by Mr. Luttring and I was going to have him identify that whenever you reached the point in interrogating on that.

Mr. Spencer: My only point in asking Mr. Smith now

was to avoid asking him questions that Mr. Luttring will testify about; so I will ask you questions only about the depreciation features of this exhibit.

Mr. Lange: We might have the witness indicate at this time, Mr. Spencer, to facilitate it also as to which of the Examiner's entries as well as which of the schedules were prepared by him and which by Mr. Luttring.

Mr. Spencer: Well, his written statement indicates what entries he is responsible for but I guess it does not indicate as to schedules.

Mr. Lange: No, it does not as to schedules. I think that will facilitate it on that.

Mr. Smith, turn to your Exhibit 176, the contents page preceding Page 1, the Examiner's Entries Nos. 400 through 406, as I understand were prepared by Mr. Luttring?

The Witness: That is correct.

Mr. Lange: And Entries Nos. 407 through 413 were prepared by you?

The Witness: That is correct.

Mr. Lange: And in so far as the schedules shown on the table of contents are concerned, which of the schedules were prepared by you?

The Witness: Schedule No. 1 and all of the schedule No. 2 except Column 3. Column 3 relates to depletion; then all the rest of the schedules from 2-A through 11, inclusive, are mine except Schedules 5 and 6 which relate to depletion, and those are Mr. Luttring's.

Mr. Lange: All right, with that information, then, I think that will segregate those.

You may proceed, then, Mr. Spencer.

Mr. Spencer: All right, thank you.

Q. Now, turn to Page 2 of your written statement. You have a schedule there which is entitled "Components of Reserve for Depreciation, 1928-1939," and in your first column you show your figures as adjusted by the Examiner which is Scheduled 1, Column 4; the second column showing per books, Schedule No. 7, and then you show the differ-

ence in the third column. The net result of your work and Mr. Luttring's work here being that the company loses approximately a million and a half depreciation and depletion heretofore accrued on its books, is that correct?

A. This million and a half applies to depreciation.

Q. Oh, that's right. I should have confined that to depreciation only. That's right, but applying it only to depreciation, is my conclusion correct?

A. Your conclusion is that we have reduced the accrued depreciation on the books?

Q. Approximately a million and a half dollars.

A. Yes, as of December 31, 1939.

Q. That's right. That, then, operates as a credit to surplus, is that correct?

A. Yes, we have treated any decrease in the reserve for depreciation as a result of this study as a contra increase in the surplus accounts in our balance sheet exhibit.

Q. Now, have you any idea what the Securities and Exchange Commission would say to a holding company or one of the holding company's operating companies that, subject to the Public Utilities Holding Company Act, which attempted to increase its surplus by rewriting its depreciation account or its depletion account? I have had some experience, so I'm trying to get what you know about it.

A. No, I haven't the slightest idea what the Securities and Exchange Commission would say under any circumstances.

Q. You wouldn't be able to testify about their attitude towards this sort of—I was going to say "manipulation." That probably isn't the right word—they probably would use it—this sort of a program. You have no knowledge of what they would say about it or their accounting rules with reference to it?

A. No, I am not in a position to state what the Securities and Exchange Commission would do—

Q. You do know that Southwestern Development Company is a registered holding company under the Public Utilities Holding Company Act, do you not?

A. Well, I don't know that to be a fact. Anything that I would say would be hearsay. I don't know it to be a fact.

Q. You do know that Canadian River Gas Company is a wholly-owned subsidiary of Southwestern Development Company?

A. Yes, there is evidence to support that in this case, as I understand it.

Q. You could move out and make a definite statement that it is for the purpose of the record—it is a 100-per cent subsidiary of Southwestern Development Company? I think counsel would stipulate that.

A. I understand that it is.

The Trial Examiner: I thought Mr. Smith so stated.

Mr. Dougherty: He said it was in the record.

The Witness: It is my understanding that testimony is in the record to that effect.

Mr. Spencer: Excuse me. I thought you had not answered.

Q. Now, on Page 3 of your written statement down about the tenth line we meet the old friend again: "* * * so that it will properly reflect the depreciation legitimately accrued on Gas Plant." You are not saying, I assume, that what the company has done is illegitimate?

A. I don't believe there is any such intention on my part.

Q. You mean by the word "legitimately" so that it will show depreciation properly in your opinion for the purpose of this particular study?

A. Well, I will go along with you on the word "properly." Now, I wouldn't like to leave the impression that I had adopted a set of accounting principles just for this study or this particular proceeding. I think we have followed good accounting principles all the way through and I think that the revised reserve for depreciation was properly accrued, not only from the standpoint of this particular study but from the standpoint of good accounting.

Q. But you aren't purporting to say that what the company has done is illegitimate?

A. No, I haven't intended to imply that.

Q. In the next paragraph, however, you do mention reclassifications and adjustments to correct various errors. I notice in the Exhibit 174 which relates to Colorado Interstate you specified some things which you thought were in error specifically. Here you do not specify specifically what errors you had in mind. Can you enlighten me on that, please?

A. Well, I think I can point out probably the principal—one of the principal objections. On Page 11, supporting Entry No. 407, I have a summary there that shows what the company's depreciation policy has been.

Q. Yes.

A. Now, they adopted a policy on January 1st, 1931 of amortizing their accounts over a 25-year period effective from that day.

Q. Would it upset your train of thought to ask you why that was done as of that date?

A. Well, of course, it is my understanding that I have gained through information obtained—from what vague information I obtained from the accounting examination, that it related to their income tax problem.

Q. Well, didn't they set their books up at that time exactly in conformity with their agreement on this subject with the Internal Revenue Bureau? And haven't they subsequently maintained their books on exactly that basis?

A. Well, as to your first question I don't know, and as to your second question, they have maintained the books on this basis with one minor exception, I believe, since 1931.

Q. All right, now, excuse me for interrupting you. Go back to the errors that you had in mind, using that phrase on Page 3 of your written statement. I think you were going to tell me why you thought this was in error.

A. As I pointed out this morning, I think that when a change in depreciation policy is made as of a certain date that the adjustments of prior accrued depreciation should be made through an adjustment of surplus as of that date if it is a significant amount, rather than spreading a correction of those errors over a series of years in the future and thereby having the wrong net income for each year of the company's existence. That is what it amounts to from an accounting point of view and from the standpoint of good accounting practice and principles and, of course, that is exactly what the company has done as I interpret the way their books were recorded.

Q. What you said on that subject this morning in connection with Exhibit No. 174 would be generally applicable here, is that correct?

A. Yes, the facts in the two situations might be slightly different, but I believe the principle is exactly the same.

Q. I believe you also brought out on cross examination

by Mr. Dougherty that the Internal Revenue Bureau would have nothing to do with your theory so far as income tax calculations are concerned, is that correct?

A. What I mean is this, If I may restate it, is that whatever expedient the Bureau of Internal Revenue uses in applying the statute under which it operates would have, would not necessarily have any bearing at all on the establishment of good accounting principles.

Q. Do you think the company should keep two sets of books, one for income tax purposes and one for rate making purposes, let us say?

A. Well, of course, you are getting into an assumption there.

Q. I am just trying to find out ultimately how many sets of books this company is going to have to keep to satisfy everybody.

A. Well, are you making the assumption that the company has to keep its set of books to obtain its statutory deductions under the Income Tax Act?

Q. Well, it may not be a complete set of books, but they have to keep certain independent data and records for that purpose which in a sense are duplications of some other set, if we followed your principles here.

A. Well, I know that in earlier years in the 1930s, a great many utility companies did keep an auxiliary set of records in order to support their deductions for income tax purposes. Now, I have been away from public accounting practice since about 1936 and I haven't kept up to date on that particular practice of companies, but I have generally understood that the recent attitude of the Bureau was such that they did not have to do that, that they were entitled to the statutory deductions under the law even though they might not agree exactly with the way they kept their general books.

Now, that is my understanding. It is not any legal conclusion on my part.

Q. All right, Mr. Smith, that is one error that you point out. Let us say an error in your opinion. Did you have any others that you thought of sufficient importance to mention?

A. I think another one of those errors shows up in one of Mr. Luttring's adjustments, probably the recorded ac-

counting on the Ingerton lease and that—on the sale of the Ingerton lease. I think that is one of the things we had in mind in making this statement in the written statement.

Q. Well, maybe I can clear it up this way sufficiently for my purposes: Your inclusion of the clause "to correct various errors" is of no serious importance here in connection with this study at all? You see I am very sensitive.

A. Yes, I have been considering, and that statement probably is a little blunt. There are a couple of things of very minor importance a couple of reclassifications there in entries 409 and 410, too, but they aren't serious.

Q. All right, we'll leave it. As I understand your testimony this morning, this exhibit is intended to be informative to the Commission and anyone else who has occasion to study this record for rate making purposes, is that right?

A. Yes, I believe that is correct.

Q. And you aren't intending by this exhibit to recommend that the company change its books and records for this period to conform to what you have found?

A. No, I don't believe that my introduction of this exhibit carries that implication with it at all.

Mr. Spencer: Well, I didn't get that impression.

That is all.

Redirect Examination.

By Mr. Lange:

Q. Mr. Smith, this morning in connection with your cross examination on Exhibit 174, Colorado Interstate Gas Company, some reference was made by you concerning a figure that you understood the Internal Revenue Bureau had used as to the life of the field or the reserves of Canadian River Gas Company and what is your information about that? What support, if any, did you have for it?

A. Well, the information that I had was just general knowledge, the general understanding of the situation that was disclosed in the accounting examination. I did not see any documents to support that theory and I got the information that the company—

Mr. Spencer: Now, wait a minute, Mr. Smith. If he knows—any figures he knows, he can put in, but if he is

going to put geological figures in here that he knows something about—

Mr. Lange: That is the very thing I want to ask him, whether that was based on any kind of an estimate or whether it was an agreed figure or whether he knows any of the facts about it at all.

The Witness: No, I really don't know what the understanding was, if any, between the Bureau and the company, and I don't know any documents on which it was based. So far as ~~I am~~ concerned, it is hearsay that I gained from talking to our Examiners who had been down there and who had questioned—it was a natural question to want to know what the company had based its depreciation accounting policy on and that was the understanding that I gained, that it has to do with income tax purposes, and I don't know what, if anything, there was to back that up on the part of the company.

Exhibit 176, in part, is as follows:

Docket G-124

CANADIAN RIVER GAS COMPANY

EXAMINER'S RECLASSIFYING AND ADJUSTING ENTRIES

RELATING TO ANNUAL AND ACCRUED DEPLETION AND DEPRECIATION.

Particulars	Debit	Credit
No. 405		
Surplus - Operating Revenue Deductions - Depletion	$110,241.42	
Reserve for Depletion of Producing Natural Gas Lands		$110,241.4

To provide annual depletion of operated acreage based on undepleted gas reserves estimated by Bureau of Engineering, undepleted cost and annual production in amounts for the years as follows:

Year	Annual Depletion	Retirements	Reserve Acquired	Depletion Reserve
as of 12/31/1927	$	$	$55,338.33	$55,338.3
1928	895.30	173.61		56,060.0
1929	2,865.07			58,925.0
1930	5,760.42			64,685.5
1931	6,225.13			70,910.6
1932	6,864.98			77,775.6
1933	6,926.97			84,702.5
1934	9,346.59			94,049.1
1935	10,908.04	3,127.78		101,829.4
1936	13,730.85			115,560.2
1937	14,682.23			130,242.5
1938	13,509.62			143,752.1
1939	18,526.22			162,278.3
Total	$110,241.42	$3,301.39	$55,338.33	$162,278.3

Undepleted reserves, annual production and total annual depletion are as follows:

(continued)

CANADIAN RIVER GAS COMPANY

No. 405 (Continued)

Year (1)	Gas Reserves (M.C.F.) (2)	Annual Production (M.C.F.) (3)	Annual Depletion: Leaseholds (4)	Annual Depletion: Gas Well Intangible Costs (5)	Annual Depletion: Total (6)	Rate per M. C. F. (7)
1928(6 months)	3,991,866,963	6,[illegible]5,097	$ 895.30	$ 2,150.05	$ 3,045.35	$ .000466
1929	3,985,331,866	19,100,448	2,865.07	6,150.34	9,015.41	.000472
1930	3,966,231,418	20,646,678	5,760.42	9,043.24	14,803.66	.000717
1931	3,945,584,740	20,819,847	6,225.13	9,473.03	15,698.16	.000754
1932	3,924,764,893	22,883,266	6,864.98	10,389.00	17,253.98	.000754
1933	3,901,881,627	21,990,394	6,926.97	10,401.46	17,328.43	.000788
1934	3,879,891,233	29,577,801	9,346.59	13,990.30	23,336.89	.000789
1935	3,850,313,432	34,628,703	10,908.04	15,998.46	26,906.50	.000777
1936	3,815,684,729	43,590,010	13,730.85	21,664.23	35,395.08	.000812
1937	3,772,094,719	46,610,252	14,682.23	24,516.99	39,199.22	.000841
1938	3,725,484,467	42,483,068	13,509.62	22,813.41	36,323.03	.000855
1939	3,683,001,399	46,783,394	18,526.22	26,339.05	44,865.27	.000959
1940	3,636,218,005					
Totals	x x x x	355,648,958	$110,241.42	$172,929.56	$283,170.98	$.000796

NOTES:

(1) All M.C.F. data above are stated on a pressure base of 14.65 pounds per square inch absolute.

(2) Gas reserves shown in column (2) represent remaining gas reserves to 25 pounds per square inch above atmosphere at beginning of each period. All amounts in column (2) were derived by adding M.C.F. produced to remaining gas reserves of 3,656,158,000 M.C.F., August 1, 1939, per estimate of Bureau of Engineering.

Exhibit No. 176

4901

7

Exhibit No. 176

Docket G-124

CANADIAN RIVER GAS COMPANY

EXAMINER'S RECLASSIFYING AND ADJUSTING ENTRIES

RELATING TO ANNUAL AND ACCRUED DEPLETION AND DEPRECIATION.

Particulars	Debit	Credit
No. 406		
Surplus - Operating Revenue		
Deductions - Depletion	$ 172,929.56	
Reserve for Depletion of Gas		
Well Intangible Costs		$ 172,929.56

To provide annual depletion of gas well intangible costs based on undepleted gas reserves estimated by Bureau of Engineering, undepleted cost and annual production in amounts for the years as follows:

Year	Annual Depletion	Retirements	Reserve Acquired	Depletion Reserve
as of 12/31/1927	$	$	$ 10,168.48	$ 10,168.48
1928	2,150.05	6,487.11		5,831.42
1929	6,150.34			11,981.76
1930	9,043.24			21,025.00
1931	9,473.03			30,498.03
1932	10,389.00			40,887.03
1933	10,401.46			51,288.49
1934	13,990.30			65,278.79
1935	15,998.46	14,345.87		66,931.38
1936	21,664.23			88,595.61
1937	24,516.99			113,112.60
1938	22,813.41			135,926.01
1939	26,339.05			162,265.06
Total	$172,929.56	$20,832.98	$10,168.48	$162,265.06

See data at end of entry No. 406 for undepleted reserves annual production and total annual depletion.

Exhibit No. 176

Docket G-124

Sheet 1 of 3

CANADIAN RIVER GAS COMPANY
EXAMINER'S RECLASSIFYING AND ADJUSTING ENTRIES RELATING TO
ANNUAL AND ACCRUED DEPLETION AND DEPRECIATION

Particulars	Debit	Credit
No. 407		
Reserve for Depreciation	$3,098,285.02	
Surplus - Operating Revenue Deductions - Depreciation		$3,098,285.02

To reverse accruals for depreciation provided in the following years:

Year	Amount
1928	$ 173,793.94
1929	348,033.71
1930	342,833.67
1931	233,848.62
1932	231,282.06
1933	234,706.42
1934	241,579.78
1935	245,288.75
1936	250,079.92
1937	256,497.10
1938	266,950.01
1939	273,391.04
	$3,098,285.02

CANADIAN RIVER GAS COMPANY
SCHEDULE OF COMPANY DEPRECIATION AND AMORTIZATION RATES
FROM INCEPTION TO DECEMBER 31, 1939

Particulars	Periods and Effective Rates		
	1928, 1929 and 1930	1931 through 1935	1931 through 1939 1/
(1)	(2)	(3)	(4)
No. 407 (Cont'd)			
[Pro]duction System			
Tangible Gas Well Equipment	10.00%	10.00%	25 Years
Drilling and Cleaning Equipment	25.00	25.00	25.00%
Field Lines			
Right-of-Way	5.00	5.00	25 Years
Construction	5.00	5.00	25 "
Equipment	5.00	5.00	25 "
Other Field Facilities			
Field Measuring Station Structures	5.00	5.00	25 Years
" " " Equipment	5.00	5.00	25 "
Field Compressor Station Structures	-	5.00	25 "
" " " Equipment	-	5.00	25 "
Gasoline Investment			
Rights-of-Way	5.00	5.00	25 Years
Structures	5.00	5.00	25 "
Equipment	8.33	8.33	8.33%
Delivery Line	5.00	5.00	25 Years
Loading Rack	8.33	8.33	8.33%
[Tra]nsmission System			
Mains and Laterals			
Rights-of-Way	5.00	5.00	25 Years
Equipment	5.00	5.00	25 "
Dehydration Plant			
Structures	-	-	25 "
Equipment	-	-	25 "
Main Compressor Station			
Structures	5.00	5.00	25 Years
Equipment	5.00	5.00	25 "
Measuring Stations			
Structures	5.00	5.00	25 Years
Equipment	5.00	5.00	25 "
Living Camp Investment			
Structures	5.00	5.00	25 Years
Equipment	5.00	5.00	25 "
[Un]distributed Fixed Capital	5.00	5.00	25 Years
[Ge]neral Property			
Office Structures	5.00	5.00	25 Years
Other Structures	5.00	5.00	25 "
General Office Equipment	10.00	10.00	10.00%
" Store "	5.00	5.00	25 Years
Telephone System	5.00	5.00	25 "
General Tools and Implements	10.00	10.00	12.50%
Other General Equipment	5.00	5.00	25 Years
General Garage Equipment (Autos and Trucks)	33.33	33.33	2/ 33.33%

1/ The Respondent adopted as of January 1, 1931, with the minor exceptions disclosed in column (4), an amortization basis of computing annual and accrued depreciation, the period for such amortization being set at 25 years. The company's plan contemplates, in general, that the accrued depreciation (amortization) reserve at the end of 25 years from January 1, 1931 will be equal to the book cost of depreciable plant.

2/ Rate of 33.33 percent was in effect to December 31, 1938; for the year [illegible] rate of 25 percent was in effect.

Exhibit No. 176

12

cket G-124

CANADIAN RIVER GAS COMPANY

EXAMINER'S RECLASSIFYING AND ADJUSTING ENTRIES

RELATING TO ANNUAL AND ACCRUED DEPLETION AND DEPRECIATION.

Particulars	Debit	Credit
No. 408		
rplus - Operating Revenue		
Deductions - Depreciation	$1,679,038.38	
Reserve For Depreciation		$1,679,038.38

To provide annual depreciation based on rvice lives estimated by Engineering Bureau for ars and in amounts as follows:

Year	Amount
1928	65,278.93
1929	139,348.16
1930	139,358.26
1931	144,877.76
1932	146,929.13
1933	147,896.12
1934	150,131.45
1935	147,867.57
1936	145,632.19
1937	144,723.45
1938	153,008.23
1939	153,987.13

See Schedule No. 1 for summary of details.

Docket G-124 — Schedule No. 4

CANADIAN RIVER GAS COMPANY
SUMMARY OF ANNUAL AND ACCRUED DEPLETION AND DEPRECIATION OF GAS PLANT
IN SERVICE AT DECEMBER 31, 1939

Line No.	Particulars (1)	Total (2)	Total Depletable Plant (3)	Total Depreciable Plant (4)	Depreciable Plant: Production Plant (5)	Depreciable Plant: Transmission Plant (6)	Depreciable Plant: General and Undistributed (7)	Non-Depreciable Plant 1/ (8)
	Costs subject to Depletion and Depreciation							
1	Original Charges Per Books	$15,536,159.96	$ 8,064,115.85	$7,467,175.44	$3,116,797.48	$3,424,819.95	$ 925,558.01	$ 4,868.67
2	Adjustments	(4,596,458.77)	(3,966,954.14)	(628,348.29)	(12,899.99)	(12,625.44)	(602,822.86)	(1,176.34)
3	Adjusted Total Cost Subject to Depletion and Depreciation	$10,939,701.19	$ 4,097,161.71	$6,838,827.15	$3,103,897.49	$3,412,194.51	$ 322,735.15	$ 3,692.33
4	Less Retirements (Adjusted)	1,016,371.25	283,657.37	732,713.88	579,230.58	33,107.17	120,376.13	-
5	Adjusted Book Cost at December 31, 1939	$ 9,923,329.94	$ 3,813,524.34	$6,106,113.27	$2,524,666.91	$3,379,087.34	$ 202,359.02	$ 3,692.33
	Depletion and Depreciation, Computed Annually; depletion computed on remaining gas reserves estimated by Bureau of Engineering and annual production of Canadian River Gas Co.; depreciation based on service life estimates furnished by Bureau of Engineering:							
	YEAR							
6	1928 (6 mos.)	$ 68,324.28	$ 3,045.35	$ 65,278.93	$ 29,794.28	32,772.40	$ 2,712.25	
7	1929	148,363.57	9,015.41	139,348.16	58,099.46	65,544.83	15,703.87	
8	1930	154,161.92	14,803.66	139,358.26	56,453.99	67,514.15	15,390.12	
9	1931	160,575.92	15,698.16	144,877.76	62,677.79	68,686.37	13,513.60	
10	1932	164,183.11	17,253.98	146,929.13	64,778.38	68,844.16	13,306.59	
11	1933	165,224.55	17,328.43	147,896.12	65,599.67	69,409.62	12,886.83	
12	1934	173,468.34	23,336.89	150,131.45	67,777.59	69,754.94	12,598.92	
13	1935	174,774.07	26,906.50	147,867.57	70,265.07	69,836.68	7,765.82	
14	1936	181,027.27	35,395.08	145,632.19	66,210.75	69,896.89	9,524.55	
15	1937	183,922.67	39,199.22	144,723.45	64,207.96	70,024.17	10,491.32	
16	1938	189,331.26	36,323.03	153,008.23	65,174.09	74,404.97	13,429.17	
17	1939	198,852.40	44,865.27	153,987.13	66,888.96	74,735.40	12,362.77	
18	Total annual accruals to December 31, 1939	$ 1,962,209.36	$ 283,170.98	$1,679,038.38	$ 737,927.99	$ 801,424.58	$ 139,685.81	-
	Less Retirement Losses:							
19	Retirements (Adjusted) (See Schedule No. 10)	$ 1,016,371.25	$ 283,657.37	$ 732,713.88	$ 579,230.58	33,107.17	$ 120,376.13	
20	Salvage (See Schedule No. 11)	(633,022.23)	(259,523.00)	(369,835.15)	(318,587.03)	(15,926.67)	(40,985.53)	
21	Profit on retirements transferred to maintenance	3,664.08			3,664.08			
22	Loss on Retirements charged to reserves	$ 387,013.10	$ 24,134.37	$ 362,878.73	$ 264,307.63	$ 17,180.50	$ 79,390.60	
23	Net (Annual Accruals less Retirement Losses)	1,575,196.26	259,036.61	1,316,159.65	471,620.36	784,244.08	60,295.21	
	Add:							
24	Reserves acquired	180,135.42	66,929.97	113,205.45	110,084.57	3,120.88		
25	Accrual charged to construction	8,031.60		8,031.60			8,031.60	
26	Deduct - Reserve applicable to Gas Plant Held for Future Use	(3,763.12)	(1,423.16)	(2,339.96)	(2,339.96)			
27	Total Reserves for Depletion and Depreciation as Adjusted of Gas Plant in Service at December 31, 1939	$ 1,759,600.16	$ 324,543.42	$1,435,056.74	$ 579,364.97	$ 787,364.96	$ 68,326.81	-
	Net Adjusted Book Cost at December 31, 1939							
28	Adjusted Original Book Cost	$ 9,923,329.94	$ 3,813,524.34	$6,106,113.27	$2,524,666.91	$3,379,087.34	$ 202,359.02	$3,692.33
29	Adjusted Depletion and Depreciation Reserves	1,759,600.16	324,543.42	1,435,056.74	579,364.97	787,364.96	68,326.81	
30	Net Book Cost - Gas Plant in Service	$ 8,163,729.78	$ 3,488,980.92	$4,671,056.53	$1,945,301.94	$2,591,722.38	$ 134,032.21	$3,692.33

Note 1/ Includes Land and Organization Expense

Parentheses denote, red figure

4911

Exhibit No. 176

ANNUAL AND ACCRUED DEPLETION AND DEPRECIATION OF
PRODUCTING PLANT

Line No.	Particulars (1)	Total (2)	Depletion: Leaseholds & Gas Well Intangible Costs (3)	Depreciation: Gas Well Tangible Costs (212) (4)	Drilling and Cleaning Equip. (216) (5)	Field Lines (206-213-214) (6)	Other Field Facilities (7)	Gasoline Property (8)
	Costs subject to Depletion and Depreciation							
1	Original Charges Per Books	$11,180,913.33	$8,064,115.85	$1,051,932.91	$ 83,338.65	$1,442,136.53	$108,965.05	$430,424.36
2	Adjustments	(3,979,834.13)	(3,966,934.14)	(15,034.69)	-	133.00	15.33	1,986.37
3	Adjusted Total Cost Subject to Depletion and Depreciation	$ 7,201,079.20	$4,097,181.71	$1,036,898.22	$ 83,338.65	$1,442,269.53	$108,980.38	$432,410.73
4	Less Retirements (Adjusted)	862,887.95	283,657.37	216,791.34	58,659.09	191,095.58	30,754.91	81,929.66
5	Adjusted Book Cost at December 31, 1939	$ 6,338,191.25	$3,813,524.34	$ 820,106.88	$ 24,679.54	$1,251,173.95	$ 78,225.47	$350,481.07
	Depletion and Depreciation, computed annually; depletion computed on remaining gas reserves estimated by Bureau of Engineering and annual production of Canadian River Gas Company; depreciation based on service life estimates furnished by Bureau of Engineering:			2.56% per annum	25.00% per annum	2.50% per annum	various rates	various rates
	Year							
6	1928 (6 mos.)	$ 32,839.65	$ 3,045.35	$ 8,538.87	$ -	$ 12,415.65	$ 786.90	$ 8,052.86
7	1929	67,114.87	9,015.41	15,397.61	2,251.64	22,932.91	1,411.91	16,105.39
8	1930	71,257.65	14,803.66	13,647.66	4,962.10	20,936.18	1,254.75	15,653.30
9	1931	78,375.95	15,698.16	17,220.53	5,724.64	21,817.92	1,339.[illegible]	16,581.39
0	1932	82,032.36	17,253.98	18,437.75	5,262.10	22,545.35	1,[illegible]	16,650.71
1	1933	82,928.10	17,328.43	17,914.85	5,742.73	25,106.60	2,228.11	16,607.40
2	1934	91,114.48	23,336.89	18,525.39	6,903.56	23,434.07	2,309.58	16,605.01
3	1935	97,171.57	26,906.50	18,645.09	6,902.74	24,308.44	2,633.94	17,774.86
4	1936	101,605.85	35,395.08	17,776.43	6,573.14	27,477.92	2,895.86	11,487.30
5	1937	103,407.18	39,199.22	18,755.43	2,986.68	27,779.47	3,098.[illegible]	11,587.82
6	1938	101,497.12	36,323.03	19,647.59	558.88	29,979.54	3,238.[illegible]	11,749.52
7	1939	111,754.23	44,865.27	20,178.20	1,314.81	30,424.51	3,223.[illegible]	11,747.91
8	Total Annual Accruals	$1,021,098.97	$ 283,170.98	$ 204,685.38	$ 19,185.02	$ 287,158.56	$ 26,297.56	$170,603.47
	Less Retirement Losses:							
9	Retirements (Adjusted)	$ 862,887.95	$ 283,657.37	$ 216,791.34	$ 58,659.09	$ 191,095.58	$ 30,754.91	$ 81,929.66
0	Salvage	(576,110.03)	(259,523.00)	(108,932.22)	(34,967.69)	(127,880.72)	(20,222.67)	(24,583.73)
1	Profit on retirements transferred to maintenance	3,664.08			3,664.08			
2	Loss on Retirements	$ 290,442.00	$ 24,134.37	$ 107,859.12	$ 27,355.48	$ 63,214.86	$ 10,532.24	$ 57,345.93
3	Net (Annual Accruals less Retirement Losses)	730,656.97	259,036.61	96,826.26	21,827.54	223,943.70	15,765.32	113,257.54
4	Add - Reserve Acquired from Amarillo Oil Co. As of December 31, 1927	177,014.54	66,929.97	110,084.57				
5	Deduct - Reserve applicable to Gas Plant Held For Future Use	(3,763.12)	(1,423.16)	(2,339.96)				
6	Reserves for Depletion and Depreciation of Production Plant in Service at December 31, 1939	$ 903,908.39	$ 324,543.42	$ 204,570.87	$ 21,827.54	$ 223,943.70	$ 15,765.32	$113,257.54
	Supporting subschedule reference						2-A	2-B
	Net Adjusted Book Cost at December 31, 1939							
7	Adjusted Original Book Cost	$ 6,338,191.25	$3,813,524.34	$ 820,106.88	$ 24,679.54	$1,251,173.95	$ 78,225.47	$350,481.07
8	Adjusted Depletion and Depreciation Reserves	903,908.39	324,543.42	204,570.87	21,827.54	223,943.70	15,765.32	113,257.54
9	Net Book Cost - Production Plant	$ 5,434,282.86	$3,488,980.92	$ 615,536.01	$ 2,852.00	$1,027,230.25	$ 62,460.15	$[illegible]

Note: Parenthesis denote red figure

4913

Exhibit No. 176

20

Exhibit No. 176

Line No.	Particulars (1)	Year	Total (2)	Field Compressor Station Structures (221B) (3)	Field Compressor Station Equipment (224B) (4)	Field Measuring Stations Structures (209M) (5)	Field Measuring Stations Equipment (215M) (6)
	Costs subject to Depreciation						
1	Original Charges Per Books		$108,965.05	$ 3,308.84	$ 16,193.38	$ 13,436.07	$ 76,026.76
2	Adjustments		15.33	--	--	—	15.33
3	Adjusted Total Cost Subject to Depreciation		$108,980.38	$ 3,308.84	$ 16,193.38	$ 13,436.07	$ 76,042.09
4	Less Retirements (Adjusted)		30,754.91		431.36	4,134.67	26,188.88
5	Adjusted Book Cost of Dec. 31, 1939		$ 78,225.47	$ 3,308.84	$ 15,762.02	$ 9,301.40	$ 49,853.21
	Depreciation, computed annually, based on service life estimated furnished by Bureau of Engineering:						
6	Annual Rates			3.33%	4.00%	4.35%	4.35%
7		1928 (6 mos.)	$ 786.90	$ --	$ --	$ 110.15	$ 676.75
8		1929	1,411.91	--	--	162.25	1,249.66
9		1930	1,254.75	--	--	106.81	1,147.94
10		1931	1,333.31	--	--	115.40	1,217.91
11		1932	1,882.47	45.97	282.42	127.51	1,426.57
12		1933	2,228.11	91.95	564.84	133.14	1,438.18
13		1934	2,309.56	104.28	609.37	132.74	1,463.17
14		1935	2,633.94	109.95	632.19	252.72	1,639.08
15		1936	2,895.96	109.95	632.33	309.79	1,843.89
16		1937	3,098.56	109.95	632.57	352.90	2,003.14
17		1938	3,238.56	109.95	632.57	385.50	2,110.54
18		1939	3,223.53	109.95	620.06	383.36	2,110.16
19	Total Annual Accruals		$26,297.56	$ 791.95	$4,606.35	$ 2,572.27	$18,326.99
	Less Retirement Losses:						
20	Retirements (Adjusted)		$30,754.91	$ --	$ 431.36	$ 4,134.67	$26,188.88
21	Less Salvage		20,222.67	--	330.55	1,800.56	18,091.56
22	Loss on Retirements		$10,532.24	$ --	$ 100.81	$ 2,334.11	$ 8,097.32
23	**Reserve for Depreciation of Other Field Facilities at Dec. 31, 1939**		$15,765.32	$ 791.95	$4,505.54	238.16	$10,229.67
	Net Adjusted Book Cost at Dec. 31, 1939						
24	Adjusted Original Book Cost		$78,225.47	$ 3,308.84	$15,762.02	$ 9,301.40	$49,853.21
25	Adjusted Depreciation Reserves		15,765.32	791.95	4,505.54	238.16	10,229.67
26	Net Book Cost - Other Field Facilities		$62,460.15	$ 2,516.89	$11,256.48	$ 9,063.24	$39,623.54

4917

Exhibit No. 176

22

Line	Particulars (1)		Total (2)	(903) (3)	(904) (4)	(902) (5)	(905) (6)	(906) (7)
0	Costs subject to Depreciation							
1	Original Charges per Books		$430,424.36	$48,552.41	$300,913.15	$242.13	$44,320.93	$36,395.74
2	Adjustments		1,986.37		1,986.37			
3	Adjusted Total Cost Subject to Depreciation		$432,410.73	$48,552.41	$302,899.52	$242.13	$44,320.93	$36,395.74
4	Less Retirements (Adjusted)		81,929.64	7.20	7,800.43	-	41,528.45	32,593.58
5	Adjusted Book Cost at December 31, 1939		$350,481.07	$48,545.21	$295,099.09	$242.13	$ 2,792.48	$ 3,802.16
	Depreciation, computed annually, based on service life estimates furnished by Bureau of Engineering:							
6	Annual rates			2.08%	3.57%	2.00%	1/ 3.33%	1/ 3.57%
		Year						
7		1928 (6 months)	$ 8,052.86	$ 389.20	$ 4,152.05	$	$ 2,201.97	$ 1,309.[illegible]
8		1929	16,105.39	778.41	8,304.10		4,402.93	2,619.95
9		1930	15,653.30	732.10	7,898.32		4,402.93	2,619.95
10		1931	16,581.39	872.73	8,685.78		4,402.93	2,619.95
11		1932	16,650.71	873.12	8,754.71		4,402.93	2,619.95
12		1933	16,607.40	887.54	8,696.98		4,402.93	2,619.95
13		1934	16,605.01	898.31	8,683.82	2.42	4,402.93	2,619.95
14		1935	17,774.86	936.13	9,712.17	4.84	4,449.43	2,674.71
15		1936	11,487.30	983.91	10,296.13	4.84	92.99	109.43
16		1937	11,587.82	984.48	10,373.49	4.84	92.99	132.02
17		1938	11,749.52	1,009.74	10,508.85	4.84	92.99	133.10
18		1939	11,747.91	1,009.74	10,505.81	4.84	92.99	134.53
19	TOTAL ANNUAL ACCRUALS		$170,603.47	$10,355.41	$106,572.21	$ 21.78	$33,440.94	$20,213.13
	Less Retirement Losses:							
20	Retirements (Adjusted)		$ 81,929.66	$ 7.20	$ 7,800.43	$ -	$41,528.45	$32,593.58
21	Less Salvage		24,583.73	6.68	3,128.79	-	8,505.97	12,942.29
22	Loss on Retirements		$ 57,345.93	$ .52	$ 4,671.64	$ -	$33,022.48	$19,651.29
23	Reserve for Depreciation of Gasoline Plant at December 31, 1939		$113,257.54	$10,354.89	$101,900.57	$ 21.78	$ 418.46	$ 561.84
	Net Adjusted Book Cost at December 31, 1939							
24	Adjusted Original Book Cost		$350,481.07	$48,545.21	$295,099.09	$242.13	$ 2,792.48	$ 3,802.16
25	Adjusted Depreciation Reserves		113,257.54	10,354.89	101,900.57	21.78	418.46	561.84
26	Net Book Cost - Gasoline Plant		$237,223.53	$38,190.32	$193,198.52	$220.35	$ 2,374.02	$ 3,240.32

1/ The delivery line to Amarillo and loading rack at Amarillo, installed in 1928, were retired in 1935. Annual depreciation as computed above from 1928 to 1935 includes an amount equal to the net retirement loss on that property. The rates indicated above apply, in effect, only to the delivery line to Exell and loading rack at Exell.

CANADIAN RIVER GAS COMPANY
Annual and Accrued Depreciation of Transmission Plant

Particulars (1)	Total (2)	Transmission Mains & Laterals (220 & 226D) (3)	Main Compressor Station Structures (221C) (4)	Main Compressor Station Equipment (224C) (5)	Measuring Stations Structures (222M) (6)	Measuring Stations Equipment (225M) (7)	Dehydration Plant Structures (223D) (8)	Dehydration Plant Equipment (227D) (9)	Mains Camp Investment Structures (223BC) (10)	Mains Camp Investment Equipment (227BC) (11)
Costs Subject to Depreciation										
Original Charges per Books	$3,424,819.95	$2,528,415.04	$95,069.80	$550,017.16	$ 6,050.85	$17,085.84	$6,193.62	$35,501.77	$164,167.42	$22,318.45
Adjustments	(12,625.44)	(7,737.69)	3,710.00	(5,953.38)	3.19	(2,741.06)	--	--	--	93.50
Adjusted Total Cost Subject to Depreciation	$3,412,194.51	$2,520,677.35	$98,779.80	$544,063.78	$ 6,054.04	$14,344.78	$6,193.62	$35,501.77	$164,167.42	$22,411.95
Less Retirements (Adjusted)	33,107.17	19,530.01	9.15	10,576.05	4.95	1,470.55	--	362.94	921.34	232.18
Adjusted Book Cost at Dec. 31, 1939	$3,379,087.34	$2,501,147.34	$98,770.65	$533,487.73	$ 6,049.09	$12,874.23	$6,193.62	$35,138.83	$163,246.08	$22,179.77
Depreciation computed annually, based on service life estimates furnished by Bureau of Engineering:										
Annual rates		Various	2.00%	2.86%	2.50%	3.57%	2.86%	4.00%	2.86%	4.00%
Year 1928 (6 mos.)	$ 32,772.40	$ 23,367.95	$ 1,017.09	$ 6,529.78	$ 62.29	$ 193.44	$ --	$ --	$ 1,577.36	$ 24.49
1929	65,544.83	46,735.90	2,034.18	13,059.56	124.58	386.89	--	--	3,154.72	49.00
1930	67,514.15	49,309.77	1,927.95	12,501.86	122.52	373.67	--	--	3,228.60	49.78
1931	68,686.37	49,412.41	2,014.02	13,322.72	127.47	407.62	--	--	3,352.35	49.78
1932	68,844.16	49,338.61	1,931.42	13,384.38	127.43	381.91	--	--	3,608.20	72.21
1933	69,409.52	49,777.71	1,931.42	13,341.54	133.51	420.02	--	--	3,650.76	154.66
1934	69,754.94	50,090.63	1,931.42	13,348.79	137.11	439.70	--	--	3,650.74	156.55
1935	69,836.68	50,102.73	1,931.42	13,343.86	138.07	442.15	--	--	3,700.04	178.41
1936	69,896.89	50,102.42	1,945.56	13,365.05	143.28	442.64	--	--	3,721.84	176.10
1937	70,024.17	50,117.48	1,945.70	13,430.36	143.28	440.56	--	--	3,772.05	174.74
1938	74,404.97	50,343.23	1,946.93	15,189.62	145.71	444.61	176.99	1,391.18	4,361.29	405.41
1939	74,735.40	50,198.30	1,975.26	15,147.15	145.91	436.39	176.99	1,390.99	4,493.90	770.51
Total Annual Accruals	$801,424.58	$ 568,897.14	$22,532.37	$155,964.67	$ 1,551.16	$ 4,809.60	$353.98	$2,782.17	$ 42,271.85	$ 2,261.64
Less Retirement Losses:										
Retirements (Adjusted)	$ 33,107.17	$ 19,530.01	$ 9.15	$ 10,576.05	$ 4.95	$ 1,470.55	--	$ 362.94	$ 921.34	$ 232.18
Less Salvage	15,926.67	9,255.16	7.35	5,367.44	3.09	722.29	--	331.55	174.17	65.62
Loss on Retirements	$ 17,180.50	$ 10,274.85	$ 1.80	$ 5,208.61	$ 1.86	$ 748.26	--	$ 31.39	$ 747.17	$ 166.56
Net (Annual Accruals less Retirement Losses).	$784,244.08	$ 558,622.29	$22,530.57	$150,756.06	$ 1,549.30	$ 4,061.34	$ 353.98	$2,750.78	$ 41,524.68	$ 2,095.08
Add - Reserve acquired from Colorado Interstate Gas Co., 5-31-33	3,120.88	2,873.00	--	--	42.74	205.14	--	--	--	--
Reserve for Depreciation of Transmission Plant in Service at Dec. 31, 1939	$787,364.96	$ 561,495.29	$22,530.57	$150,756.06	$ 1,592.04	$ 4,266.48	$ 353.98	$2,750.78	$ 41,524.68	$ 2,095.08
Supporting subschedule reference	-	3-A								
Net Adjusted Book Cost at Dec. 31, 1939										
Adjusted Original Book Cost	$3,379,087.34	$2,501,147.34	$98,770.65	$533,487.73	$ 6,049.09	$12,874.23	$6,193.62	$35,138.83	$163,246.08	$22,179.77
Adjusted Depreciation Reserves	787,364.96	561,495.29	22,530.57	150,756.06	1,592.04	4,266.48	353.98	2,750.78	41,524.68	2,095.08
Net Book Cost - Transmission Plant	$2,591,722.38	$1,939,652.05	$76,240.08	$382,731.67	$ 4,457.05	$ 8,607.75	$5,839.64	$32,388.05	$121,721.40	$20,084.69

Note: Parentheses denote figure in red.

4919 Exhibit No. 176

Subschedule No. 3-A

CANADIAN RIVER GAS COMPANY
ANNUAL AND ACCRUED DEPRECIATION OF TRANSMISSION MAINS AND LATERALS
(ACCOUNTS 220D & 226D)

ne o.	Particulars (1)		Total (2)	Main Line (3)	Clayton Lateral (4)	Dalhart Lateral (5)	Texline Lateral (6)
	Costs Subject to Depreciation						
1	Original Charges per Books		$2,528,415.04	$2,478,159.00	$34,746.02	$6,257.51	$9,252.51
2	Adjustments		(7,737.69)	(3,239.42)	(4,498.27)	-	-
3	Adjusted Total Cost Subject to Depreciation		$2,520,677.35	$2,474,919.58	$30,247.75	$6,257.51	$9,252.51
4	Less Retirements (Adjusted)		19,530.01	10,608.87	8,812.88	99.42	8.84
5	Adjusted Book Cost at December 31, 1939		$2,501,147.34	$2,464,310.71	$21,434.87	$6,158.09	$9,243.67
	Depreciation, computed annually, based on service life estimates furnished by Bureau of Engineering:	YEAR					
6	Annual rates			2.00%	2.50%	2.50%	2.50%
7		1928 (6 months)	$ 23,367.95	$ 23,194.31	$	$ 59.40	$ 114.15
8		1929	46,735.90	46,388.62		118.99	228.29
9		1930	49,309.77	48,938.68		144.31	226.78
10		1931	49,412.41	49,039.40		146.23	226.78
11		1932	49,338.61	48,961.38		150.67	226.56
12		1933	49,777.71	48,961.86	438.69	150.60	226.56
13		1934	50,090.63	48,961.85	751.62	150.60	226.56
14		1935	50,102.73	48,970.31	751.66	154.20	226.56
15		1936	50,102.42	48,969.92	751.74	154.20	226.56
16		1937	50,117.48	48,983.61	753.11	154.20	226.56
17		1938	50,343.23	49,204.74	753.24	154.20	231.05
18		1939	50,198.30	49,278.73	534.53	153.95	231.09
19	Total Annual Accruals		$ 568,897.14	$ 559,853.41	$ 4,734.59	$1,691.64	$2,617.50
	Less Retirement Losses:						
20	Retirements (Adjusted)		$ 19,530.01	$ 10,608.87	8,812.88	99.42	8.84
21	Less Salvage		9,255.16	6,763.94	2,402.31	80.07	8.84
22	Loss on Retirements		$ 10,274.85	$ 3,844.93	$ 6,410.57	$ 19.35	$ -
23	Net (Annual Accruals less Retirement Losses)		$ 558,622.29	$ 556,008.48	$(1,675.98)	$1,672.29	$2,617.50
24	Add - Reserve Acquired from Colorado Interstate Gas Co., 5-31-33		2,873.00		2,873.00		
25	Reserve for Depreciation of Transmission Mains and Laterals at December 31, 1939		$ 561,495.29	$ 556,008.48	$ 1,197.02	$1,672.29	$2,617.50
	Net Adjusted Book Cost At December 31, 1939						
26	Adjusted Original Book Cost		$2,501,147.34	$2,464,310.71	$21,434.87	$6,158.09	$9,243.67
27	Adjusted Depreciation Reserves		561,495.29	556,008.48	1,197.02	1,672.29	2,617.50
28	Net Book Cost - Transmission Mains & Laterals		$1,939,652.05	$1,908,302.23	$20,237.85	$4,485.80	$6,626.17

Note: Parentheses denote red figure.

4921

Exhibit No. 176

24

CANADIAN RIVER GAS COMPANY
ANNUAL AND ACCRUED DEPRECIATION OF GENERAL AND UNDISTRIBUTED PLANT

Particulars (1)	Total (2)	Undistributed Fixed Capital 1/ (3)	General Office Structures (372) (4)	Other General Structures (372) (5)	General Office Equipment (392) (6)	General Stores Equipment (393) (7)	General Garage Equipment (Autos, etc.) (395) (8)	Telephone System Equipment and Right-of-Way (371 and 397) (9)	General Tools and Equipment (396) (10)	Other General Equipment (378) (11)
Costs Subject to Depreciation										
Original Charges per Books	$985,558.01	$618,832.70	$2,793.03	$34,380.00	$14,686.65	$6,204.67	$145,356.48	$87,667.39	$12,368.63	$3,388.46
Adjustments	(602,822.86)	(605,483.75)						1,814.00		[illegible]
Adjusted Total Cost Subject to Depreciation	$382,735.15	$13,348.95	$2,793.03	$34,380.00	$14,686.65	$6,204.67	$145,356.48	$89,481.39	$12,368.63	$4,175.35
Less Retirements (Adjusted)	180,376.13	-	-	791.96	2,951.38	50.48	109,278.08	3,068.25	4,017.77	278.21
Adjusted Book Cost at December 31, 1939	$202,359.02	$13,348.95	$2,793.03	$33,588.04	$11,735.27	$6,154.19	$36,078.40	$86,413.14	$8,350.86	$3,897.14
Depreciation, computed annually, based on service life estimates furnished by Bureau of Engineering:										
Annual rates		2.00%	2.86%	2.86%	4.00%	2.86%	25.00%	3.12%	6.67%	5.00%
Year										
1928 (6 months)	$ 2,712.85	$ 136.04	$ 38.96	$ 91.49	$ 225.86	$ 32.57	$ 745.11	$ 1,039.06	$ [illegible]	$ 21.71
1929	15,703.67	272.08	77.92	182.98	451.71	65.14	11,849.60	2,078.13	682.09	43.42
1930	15,390.12	272.08	78.90	209.88	510.88	78.66	11,949.73	2,106.42	535.79	48.76
1931	13,513.60	266.98	78.37	220.79	534.93	130.61	9,675.79	2,137.71	209.05	20.19
1932	13,306.59	266.98	833.94	220.73	587.94	132.64	9,271.08	2,348.27	180.42	64.94
1933	12,886.63	266.98	78.37	394.48	595.55	141.41	8,989.53	2,588.22	177.86	119.05
1934	12,598.92	266.98	78.37	408.06	597.17	143.13	8,088.98	2,587.77	306.08	124.84
1935	7,765.82	266.98	79.20	430.43	573.05	143.13	3,194.96	2,588.00	371.19	118.08
1936	9,524.55	266.98	79.20	431.57	808.67	139.42	4,667.35	2,607.83	400.57	122.76
1937	10,491.32	266.98	79.20	488.44	840.37	150.86	5,504.78	2,605.66	411.05	123.94
1938	13,429.17	266.98	79.20	495.62	874.41	153.67	8,369.27	2,605.66	401.14	144.76
1939	12,362.77	266.98	79.88	937.86	905.75	174.92	6,676.99	2,661.94	469.40	190.15
TOTAL ANNUAL ACCRUALS	$139,665.81	$ 3,083.02	$1,061.11	$ 4,511.77	$ 7,505.85	$1,486.38	$ 88,372.52	$27,994.85	$ 4,486.30	$1,183.94
Less Retirement Losses:										
Retirements (Adjusted)	$180,376.13	$ -	$ -	$ 731.96	$ 2,951.38	$ 50.48	$109,278.08	$ 3,066.85	$ 4,017.77	$ 278.21
Less Salvage	40,985.53	-	-	83.59	792.53	47.91	35,133.64	1,143.67	3,538.05	246.94
Loss on Retirements	$ 79,390.60	-		$ 648.37	$ 2,158.85	$ 2.57	$ 74,144.44	$ 1,923.18	$ 479.72	$ 31.27
Net (Annual Accruals less Retirement Losses)	$ 60,295.21	$ 3,083.02	$1,061.11	$ 3,863.40	$ 5,347.04	$1,483.81	$ 14,228.07	$26,070.47	$ 4,007.58	$1,150.71
Add Accrual charged to Construction	8,031.60						8,031.60			
Reserve for Depreciation of General and Undistributed Plant at December 31, 1939	$ 68,326.81	$ 3,083.02	$1,061.11	$ 3,863.40	$ 5,347.04	$1,483.81	$ 22,259.67	$26,070.47	$ 4,007.58	$1,150.71
Net Adjusted Book Cost at December 31, 1939:										
Adjusted Original Book Cost	$202,359.02	$ 13,348.95	$2,793.03	$33,588.04	$11,735.27	$6,154.19	$ 36,078.40	$86,413.14	$ 8,350.86	$3,897.14
Adjusted Depreciation Reserves	68,326.81	3,083.02	1,061.11	3,863.40	5,347.04	1,483.81	22,259.67	26,070.47	4,007.58	1,150.71
Net Book Cost - General and Undistributed Plants	$134,032.21	$ 10,265.93	$1,731.92	$29,724.64	$ 6,388.23	$4,670.38	$ 13,818.73	$60,342.67	$ 4,343.28	$2,746.43

1/ Excludes organization expense in the amount of $387.45.

Note: Parentheses indicate red figures.

Exhibit No. 176

25 4923

Docket G-124

Schedule No. 5

CANADIAN RIVER GAS COMPANY
ANALYSIS OF RESERVE FOR DEPLETION OF LEASES AND
GAS WELL INTANGIBLE COSTS PER BOOKS FROM INCEPTION TO
DECEMBER 31, 1939

Year (1)	Balance at Beginning of Period (2)	Annual Accruals For Depletion (Expense) (3)	Retirements: Plant Cost (4)	Retirements: Salvage (5)	Retirements: Profit or Loss on Retirements (6)	Retirements: Net Charge to Reserve (Col. 4, 5 & 6) (7)	Adjustments of Prior Years Depletion (through surplus) (8)	Miscellaneous (9)	Balance at End of Period (10)
1928	-	$ 41,960.01						1/ $66,929.97	$ 108,889.98
1929	$ 108,889.98	125,130.79	$(346,832.70)		$340,171.98	$(6,660.72)			227,360.05
1930	227,360.05	85,711.54	(38,221.38)			(38,221.38)			274,850.21
1931	274,850.21	92,910.21				-			367,760.42
1932	367,760.42	114,997.29				-			482,757.71
1933	482,757.71	130,809.28					$(3,337.13)) 9,803.52)		620,033.38
1934	620,033.38	151,736.27				-			771,769.65
1935	771,769.65	87,314.17	(46,984.41)	$44,625.00	(2,968.06)	(5,327.47)			853,756.35
1936	853,756.35	118,821.44					(2,657.33)		969,920.46
1937	969,920.46	130,661.30					3,337.13) (11,489.57))		1,092,429.32
1938	1,092,429.32	140,959.72					(65,378.11)		1,168,010.93
1939	1,168,010.93	320,359.14							1,488,370.07
		$1,541,371.16	$(432,038.49)	$44,625.00	$337,203.92	$(50,209.57)	($69,721.49)	$66,929.97	

Note: 1/ Accrued depletion as of 12-31-27 acquired from Amarillo Oil Company

Parentheses denote red figure.

Exhibit No. 176

4925

28

ANALYSIS OF RESERVE FOR DEPLETION OF LEASES AND GAS WELL INTANGIBLE COSTS, AS ADJUSTED, FROM INCEPTION TO DEC, 31, 1939

Year	Balance at Beginning of Period	Annual Accruals for Depletion (Expense)	Retirements Plant Cost	Retirements Salvage	Miscellaneous	Balance at End of Period
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1928	$	$ 3,045.35	($214,513.29)	$207,852.57	$ 65,506.81	$ 61,891.44
1929	61,891.44	9,015.41				70,906.85
1930	70,906.85	14,803.66				85,710.51
1931	85,710.51	15,698.16				101,408.67
1932	101,408.67	17,253.98				118,662.65
1933	118,662.65	17,328.43				135,991.08
1934	135,991.08	23,336.89				159,327.97
1935	159,327.97	26,906.50	(69,144.08)	51,670.43		168,760.82
1936	168,760.82	35,395.08				204,155.90
1937	204,155.90	39,199.22				243,355.12
1938	243,355.12	36,323.03				279,678.15
1939	279,678.15	44,865.27				324,543.42
		$283,170.98	($283,657.37)	$259,523.00	$ 65,506.81	

Note: Parentheses denote red figure

Docket G-124

CANADIAN RIVER GAS COMPANY
ANALYSIS OF RESERVE FOR DEPRECIATION OF GAS PLANT IN SERVICE, PER BOOKS,
FROM INCEPTION TO DECEMBER 31, 1939

Schedule No. 7

Year (1)	Balance at Beginning of Period (2)	Annual Accruals For Depreciation: Expense (3)	Annual Accruals For Depreciation: Plant (4)	Retirements: Plant Cost (5)	Retirements: Salvage (6)	Retirements: Profit or Loss on Retirements (7)	Net Charge to Reserve (Col. 5, 6 & 7) (8)	Adjustment of Prior Years Depreciation (through surplus) (9)	Miscellaneous (10)	Balance at End of Period (11)
1928	$ -	$182,737.99	$8,031.60	$ (1,546.53)	$ 1,546.53	$ -	$ -	$ -	1/ $144,315.05	$ 335,084.64
1929	335,084.64	349,500.15		(175,074.69)	9,700.55	132,546.52	(32,827.62)	(8,944.05)	2/ (34,230.48)	608,582.64
1930	608,582.64	348,462.58		(32,307.78)	8,406.30	3,140.18	(20,071.30)			936,373.92
1931	936,373.92	370,225.88		(44,353.21)	27,972.75	5,562.99	(10,817.47)	(1,322.02)		1,294,460.31
1932	1,294,460.31	371,508.20		(104,666.46)	51,723.89	5,917.39	(47,025.18)			1,618,943.33
1933	1,618,943.33	367,198.32		(18,774.43)	8,910.01	2,287.03	(7,577.39)	(1,096.52)		1,977,467.74
1934	1,977,467.74	384,961.45		(39,612.47)	15,984.62	8,792.45	(14,835.40)		3/ 6,653.61	2,336,247.40
1935	2,336,247.40	362,209.28		(197,547.57)	33,635.93	90,459.22	(73,452.42)	(4,676.33)		2,620,327.93
1936	2,620,327.93	247,809.29		(52,761.45)	31,001.97	3,092.98	(18,666.50)			2,849,470.72
1937	2,849,470.72	257,113.39		(77,814.31)	30,350.53	17,075.54	(30,388.24)	(660,832.62)		2,415,363.25
1938	2,415,363.25	266,950.01		(43,037.80)	15,804.42	(1,537.10)	(28,770.48)	40,273.32		2,693,816.10
1939	2,693,816.10	273,391.04		(25,557.70)	14,010.81	(131.78)	(11,678.67)			2,955,528.47
		$3,764,067.58	$8,031.60	$(813,054.40)	$247,138.31	$267,[illegible]05.42	$(296,[illegible]10.67)	$(636,5[illegible])	$116,7[illegible]	

Note: 1/ Accrued depreciation as of 12-31-27 acquired from Amarillo Oil Co.

2/ Adjustment of accrued depreciation acquired from Amarillo Oil Co. (See Note 1/).

3/ Accrued depreciation on Clayton Lateral acquired from Colorado Interstate Gas Co.

Parentheses denote red figure.

Exhibit No. 176

28

ot G-124 Schedule No. 8

CANADIAN RIVER GAS CO.

Analysis of Reserve for Depreciation of Gas Plant in Service
As Adjusted, from Inception to Dec. 31, 1939

Balance at Beginning of Period	Annual Accruals For Depreciation Expense	Plant	Retirements Plant Cost	Salvage	Profit on Drilling and Cleaning Equip't Credited to Acct. 367	Net Charge to Reserve	Miscellaneous	Balance at end of Period
(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
$	$ 65,278.93	$ 8,031.60	($146,833.88)	$124,885.24	$	($21,948.64)	1/ $107,744.61	$159,106.50
159,106.50	139,348.16		(23,471.88)	9,700.55		(13,771.33)		284,683.33
284,683.33	139,358.26		(32,925.17)	15,560.17		(17,365.00)		406,676.59
406,676.59	144,877.76		(32,743.32)	20,908.88		(11,834.44)		539,719.91
539,719.91	146,929.13		(104,666.46)	51,726.87	1,098.76	(51,840.83)		634,808.21
634,808.21	147,896.12		(18,774.43)	8,992.61	(1,029.45)	(10,811.27)		771,893.06
771,893.06	150,131.45		(38,682.47)	15,134.95	(3,278.34)	(26,825.86)	2/ 3,120.88	898,319.53
898,319.53	147,867.57		(140,792.90)	34,587.93	(324.48)	(106,529.45)		939,657.65
939,657.65	145,632.19		(52,761.45)	31,812.93	19.72	(20,928.80)		1,064,361.04
1,064,361.04	144,723.45		(78,181.31)	30,420.13	(146.35)	(47,907.53)		1,161,176.96
1,161,176.96	153,008.23		(37,322.91)	15,758.16	(3.94)	(21,568.69)		1,292,616.50
1,292,616.50	153,987.13		(25,557.70)	14,010.81		(11,546.89)		1,435,056.74
	$1,679,032.38	$ 8,031.60	($373,713.88)	$373,499.23	($3,664.08)	($354,[illegible]78.03)	$110,865.49	

Note: 1/ Accrued Depreciation as of 12-31-27 acquired from Amarillo Oil Co. (Adjusted)

2/ " " on Clayton Lateral acquired from Colo. Interstate Gas Co.

Parentheses denote red figure.

Exhibit No. 176

29

Commission WITNESS LUTTRING testified as follows: (Vol. L, pp. 6937-6950.)

Direct Examination

By Mr. Lange:

Q. You are the same Carl E. Luttring who has heretofore testified in these proceedings?

A. Yes, sir.

Q. Mr. Luttring, I will ask you whether or not in—strike that.

I will ask you whether you assisted in the preparation of Exhibit 176 that has been identified in this proceeding?

A. I have.

Q. And turning to the contents table of that exhibit, I will ask you whether you prepared the entries numbered 400 through 406, inclusive?

A. I did.

Q. And now which schedules did you prepare in connection with that exhibit?

A. I supplied the figures relating to depletion which were used in Schedule No. 2. I also prepared Schedules Nos. 5 and 6.

Q. Now, as I understand this Exhibit 176, in connection with the preparation of which you devoted your time, and on completion of the exhibit it was approved by Charles W. Smith, Chief, Bureau of Accounts, Finance and Rates of the Federal Power Comission?

A. That is correct.

Q. And bears such approval on its title page?

A. That is correct.

Q. And you heard the written statement in connection with that exhibit that was read by Mr. Smith on direct examination?

A. I did.

Q. And in so far as it refers to those entries and schedules that you prepared, that may also be taken as your written statement of that portion of the exhibit?

A. It can.

Mr. Lange: I believe that is all at this time.

Cross Examination

By Mr. Spencer:

Q. These schedules of yours, Mr. Luttring, Schedules 5 and 6 on Pages 26 and 27 of Exhibit 176, summarize your work in connection with this exhibit, Schedule No. 5 showing—

A. Schedule No. 5 on Page 26 and Schedule No. 6 on Page 27 represent my work.

Q. Well, can't we get a good picture of what you have done by reference to those tables?

A. These schedules combined with the journal entries will give you a complete picture of what the books were before we adjusted them in our exhibit and what the results are after applying our adjustments.

Q. All right, now, let's get some idea about the depletable base that we are talking about here. I assume that you start off with depletion accrued on—by deducting the depletion accrued on the books of the Amarillo Oil Company at the time it sold its gas properties and rights to Canadian River Gas Company?

A. The depletion accrued that was acquired from Amarillo Oil Company has remained intact. In other words, the figure was not disturbed and it forms a part of the accrued depletion as of December 31, 1939.

Q. You did not disturb that?

A. No, sir.

Q. Now, the depletable base here includes your adjusted cost of leaseholds, is that right?

A. That is correct.

Q. Adjusted in your original cost study exhibit 146?

A. Exhibit 146 is correct.

Q. You carried that original cost over here as related to leaseholds for the purpose of depletion, is that right?

A. That is correct.

Q. Which is somewhat less than the company is depleting on its books?

A. I think it was considerably less.

Q. Now, in addition to your adjusted original cost for leaseholds you also include in the depletable base the company's original costs of intangibles. I mean particularly intangibles in connection with the drilling of wells, is that correct?

A. Yes, what is ~~known as gas~~ well intangible costs.

Q. And those consist generally of what?

A. Drilling, labor, teaming and freight and incidentals which are not in the nature of depreciable items.

Q. That's right. The physical property in the wells such as the pipe or casings and well fittings are subject to depreciation and not depletion, is that correct?

A. That is right, and it has been so treated in our depreciation exhibit.

Q. What is the depletable base you find here as of December 31, 1939, representing leasehold cost and intangible well costs as adjusted by you?

A. On Schedule No. 1, Line No. 5—

Q. That page is 20—

A. 19.

Q. Yes.

A. Column No. 3.

Q. Yes.

A. That is the total depletable plant. The adjusted book cost as of December 31, 1939 of total depletable plant can be found in Exhibit 146 if you wish to refer back to it.

Q. No, I think that's all right. What was your original cost of gas leaseholds and gas rights and wells acquired by Canadian River from Amarillo Oil Company? Do you remember what that was?

A. The operated leasehold costs amounted to $835,271.68 and the unoperated leasehold costs amounted to $158,228.70. That will be shown on Schedule No. 2 in Exhibit 146.

Q. Yes, but you had some wells to add to that, too, on which you put inventory value as I remember. I am trying to arrive at the total original cost of the properties sold by Amarillo Oil Company to Canadian River Gas Company as you show it.

A. I am just wondering whether I won't have to refer back to my working papers.

Q. Can you give me the rough figures? Is a million and a half approximately correct?

A. That is approximately correct, yes.

Q. Well, that's sufficient for my purpose here. Now, I believe you also testified here that there is no question but what Canadian River paid five million dollars for these properties?

A. That is correct.

Q. Now, what I wanted to ask you, as an accountant how would you recommend that the company go about amortizing this three and a half million dollars that you are throwing out?

A. Well, knowing what I do about the company, I would hesitate to do anything with the three and a half million dollars.

Q. Do you mean you would just leave it in a state of suspended animation or something?

A. If I had to set it up I would probably set it up as I have in here, set it up as a separate item.

Q. It has got to be written off in some fashion, hasn't it, at some time?

A. Well, it probably would be a good thing to get it off the books.

Q. I wish you would consider that. I may have some more questions to ask you on that.

Now, I would like to go to your basis of computing depletion during this period. The explanation given in the written statement starts at the bottom of Page 3. I would like to follow through with you on that. Have you found that?

A. Yes.

Q. It states: "As of August 1st, 1939, the volume of the company's remaining gas reserve was estimated by the Bureau of Engineering as being 3,656,158,000 thousand cubic feet, at 14.65 pounds per square inch absolute pressure."

That figure was furnished to you by the Bureau of Engineering of the Federal Power Commission?

A. It was.

Q. Did you ask for it?

A. No, I did not.

Q. Well, you didn't give the Engineering Department instructions about doing this engineering work for you in connection with this study, then?

A. No, sir.

Q. Who did give instructions?

A. As far as I know, the Engineering Department.

Q. Did you get your instructions from the Engineering Department?

A. No. I say, the Engineering Department gave instructions to get these gas reserves.

Q. Well, where did you get your instructions from?

A. Well, I didn't really need any instructions after I was supplied with this gas reserve figure shown in our statement—the written statement. It was a matter of using it in application in determining the new annual depletion amounts.

Q. Well, isn't this a fact, that you were instructed to work on and prepare these depletion schedules here and in that connection you needed the reserve figure and it was handed to you by the Engineering Bureau of the Federal Power Commission and you accepted it, isn't that correct?

A. That is correct.

Q. You didn't stop to think whether it was the right figure or the wrong figure, you took it, didn't you?

A. I would have no way of knowing. Of course, that particular work is not in my line.

Q. Did you ever set up a depletion schedule for gas companies before?

A. I don't believe I did.

Q. You had no previous experience in preparing a depletion schedule of this character for a natural gas company?

A. I have had some experience but it was something that had already been set up.

Q. I mean in reconstructing or originating depletion schedules for a natural gas company, you haven't done that?

A. Not in this same type of work.

Q. Are there different methods utilized by natural gas companies in setting up depletion schedules?

A. I don't know of any other than the one that is used here.

Q. This is the only one you know about?

A. That's right.

Q. All right, are you familiar with the company's now using it—of computing this depletion?

A. Yes, sir.

Q. That is a different one, isn't it?

A. Well, it is very much on the same order as this one.

Q. Oh, they seem to be the same to you?

A. Very much so.

Q. Very similar—what is the company's method of computing depletion?

A. The company, instead of using a reserve applicable

to its own acreage, used a gas reserve which is applicable to the entire Amarillo gas field and in determining its annual depletion it used the production of the entire Amarillo gas field.

Q. That is correct, and from that they arrive at the unit cost depletion factor to apply to their own production is that right?

A. That is correct.

Q. Now, in other words, the company in computing its depletion costs has based it upon the life of the field, that is correct, is it not?

A. Under the company's method—

Q. Yes.

A. Yes.

Q. Now, state for the Examiner in the same way what the method has been employed by the Commission's engineers and by you in computing the depletion.

A. Well, under this method the engineers have given us a gas reserve estimate which applies to the actual acreage owned by Canadian River Gas Company. The production we used is the production which was actually taken from this same acreage.

Q. By whom?

A. By Canadian River Gas Company. The unit cost of depletion is determined by dividing the undepleted cost of the investment in the leases by the unrecovered gas reserves in those leases. The unit cost so obtained is then applied to the production which the company has taken from those leases.

Q. Have you finished?

A. Yes.

Q. All right, then, arriving at the unit cost of depletion for the purpose of your study here, you have taken into consideration no withdrawals from Canadian River Gas Company reserves as computed except its own production, is that correct?

A. That is correct.

Q. Now, did you ask your Engineering Department before you started computing these schedules to furnish you with a figure of withdrawals that might be sustained by the company through drainage to show how much the property had been actually depleted?

A. By "drainage," do you mean drainage by other operators?

Q. Certainly, certainly, that and any other kind of drainage.

A. That is not an accounting problem as far as I can see it.

Q. Well, did you ask them for that?

A. No, sir.

Q. Were you concerned about it?

A. I was not.

Q. Then, so far as you were concerned, the only figure that you needed was the withdrawals as shown by Canadian River production—nothing more?

A. That is correct.

Q. Had your engineers told you that the property was going to sustain withdrawals through drainage, it would have changed your figures, wouldn't it?

A. I don't think so because you have got both sides of the question there. You have got drainage in as well as out.

Q. No, I said to you, if your engineers had told you that the property was going to sustain a loss of gas reserves through drainage, let us assume—you can assume that for the purpose of this question—it would have changed your figures, would it not?

A. It may have changed the geologist's figures if he had to give some weight to that.

Q. No, I am talking only about production withdrawals. Let the other figure stand. Depletion is suffered by production by a loss of gas from the property, whether it comes through our own wells or somebody else's wells.

A. It would not change my figures.

Q. No matter what drainage we might suffer, it wouldn't change your figures?

A. No, sir.

Q. You would stay right with your guns?

A. Yes, sir.

Q. Now, I believe you stated that the reserve figure that you use here is treating all of Canadian River Gas Company's leases as one *reservour*?

A. That is correct.

Q. Now, from the standpoint of accounting, then, you are treating the whole reserve as one reservoir?

A. That is correct.
Q. You do recognize, then, that as between leases in the total reservoir the gas moves all around, back and forth, is that correct?

Mr. Lange: Well, I think—

Mr. Spencer: Now, wait a minute—go ahead.

Mr. Lange: Between leases the gas travels back and forth; that is purely an engineering problem.

Mr. Spencer: I'll come to it in just a minute.

The Trial Examiner: Did you question—your question is whether or not he recognized that?

Mr. Spencer: Yes, sir.

The Trial Examiner: He may answer that.

The Witness: I think we have.

Mr. Spencer: I think you have, too.

Q. If you weren't going to treat it as a whole and assumed it was going to be produced as a whole, you would set up each leasehold separately and give its own gas reserve, wouldn't you?
A. That is correct.
Q. You recognize this drainage between leases—you treat this entire block of acreage as one reservoir, but when you get over to a different title you ignore that and say there isn't any drainage. Did you give that any thought?
A. I did not give any thought to it in this study here.
Q. You are including unoperated leases in here for depletion purposes, aren't you?
A. That is correct.
Q. Leases with no wells on them, is that right?
A. That is correct.

* * * * * * *

Mr. Eutting further testified: (Vol. L, pp. 6952-6956.)

Q. All right, now, the last one that you had to do with, Entry 406 on Page 8?
A. Entry No. 406 on Page 8 sets up annual depletion according to our computation of gas well intangible costs based on undepleted gas reserves estimated by the Bureau

of Engineering and undepleted cost and annual production in amounts for the years as set forth in the body of that journal entry.

Q. You can go back on Page 7 of the chart there, it is included there, too?

A. Yes, in support of Journal Entry No. 406, are statistics which support also Entry No. 405.

Q. And 406?

A. I said also.

Q. You said also 405, did you not?

A. All right, make it "and 406."

Q. All right, I believe that clears that up as to what you have done.

With your permission and counsel's permission we have a photostatic copy of one of your working papers relating to intangible well costs and on that sheet under the column headed "Balance December 31, 1939" there is a figure of $162,391.84 appearing opposite the description "Miscellaneous." Will you tell me what that is, please?

A. On the gas well investment records of Canadian River Gas Company they carry a column headed "Miscellaneous." In this column is entered items which cannot fall under the description of labor, teaming and freight, drilling, torpedoes, depreciation and adjustment, rigs. It is a sort of a dumping ground for items which cannot be classified into the features just stated.

Many of the items in this miscellaneous column cannot be identified without a great deal of analysis work and for that reason we have used the entire charges in the miscellaneous account as a part of our depletable base of intangible well costs. Our Bureau of Engineering felt that it was advisable to do this rather than spend a great deal of time to try to identify such depreciable items as may be in that account. I think that about covers it.

Q. That is sufficient, Mr. Luttring.

Now, the company on its books and records carries this miscellaneous well cost as a depreciable item, does it not?

A. That is correct.

Q. And if that classification were correct, or assuming it were correct, under your study here the company would

be entitled to take depreciation against the item in the amount of 2.56 per cent per year, is that right?

A. Yes, whatever rate of depreciation applies against gas well equipment.

Q. Well, I am taking the gas well tangible cost rate as shown on Page 20 of your exhibit. Now, you have taken that out of the classification of depreciable property and put it over into depletable property, that is correct, isn't it?

A. That is correct.

Q. Where based upon past experience, at least, and based upon your computations, it would draw a much lower rate of depletion than it would have of depreciation, is that not correct?

A. Well, just how much lower depletion on that would be over the other, I am not prepared to say, but I do think it will be lower.

Q. Well, that is a matter of calculation?

A. Yes, that is what it is.

Q. Now to clear that up, then, you can't tell from the company's books exactly what items of property go into these miscellaneous—this miscellaneous account?

A. That is correct.

Q. That would involve a lot of work which you did not do?

A. Not only that, but I think that even if you do it you will still find that a lot of those items will be intangible items even after analysis.

Q. Well, that may be true; we do not know that it is true right at the moment, though?

A. No, that is correct.

Mr. Spencer: I think that is all.

The Trial Examiner: Do you have some redirect, Mr. Lange?

Mr. Lange: Just this:

Redirect Examination

By Mr. Lange:

Q. You were interrogated with reference to the recoverable gas reserves of the Canadian River Gas Company. What is your understanding of the use of that term as employed

A. My understanding of the use of the word "recoverable" is that it represents the gas which will be ultimately recovered from the leases owned by Canadian River Gas Company.

Mr. Lange: That is all.

The Trial Examiner: Is that all? Do you have anything further?

Mr. Spencer: Let me see.

Recross Examination.

By Mr. Spencer:

Q. Then your computations are based upon the theory that Canadian River will recover all of the gas that is shown here as constituting its reserve?

A. That is my understanding.

Q. To-wit: three trillion plus cubic feet?

A. That is my understanding.

Q. Down to twenty-five pounds? I guess they have that qualification. That is some place here, is that correct?

A. That is correct.

Q. And if anything went wrong with that assumption at any point, then your computations would be incorrect to that extent?

A. That is correct.

Through the Witness Hill the Commission presented Exhibit 178, in which exhibit the service lives of the physical properties of Canadian are set forth. This exhibit is similar to Exhibit 177 which was also presented by this witness in connection with Colorado Interstate. The service lives for the main transmission lines and for the structures in Bivins Compressor Station are estimated at 50 years. Other structures and equipment range from 20 to 48 years; gas well equipment, 39; field lines, 40 years; other field line facilities from 23 to 30 years; and general garage and general office equipment, 4 years and 12½ years, respectively.

Exhibit 178 is, in part, as follows:

Statement of Composite Service Lives Determined for Property of Canadian River Gas Company

Account Number and Name		Adjusted Book Cost 12-31-39	Service Life (Years)	Annual Straight Line Rate—%
Leaseholds				
205	Leaseholds—Operated	$ 1,545,877.52		
205	Leaseholds—Unoperated	58,143.09		
	Total Leaseholds	$ 1,604,020.61		
Gas Wells				
211	Construction	$ 2,209,503.73		
212	Equipment	820,106.88	39	2.56
	Total Gas Wells	$ 3,029,610.61		
Drilling and Cleaning Equipment				
216	Drilling and Cleaning Equip.	$ 24,679.54		
Field Lines				
206-B	Rights-of-Way	$ 21,413.66	40	2.50
213-B	Construction	337,605.21	40	2.50
214-B	Equipment	892,155.08	40	2.50
	Total Field Lines	$ 1,251,173.95		
Other Field Facilities				
209-M	Field Measuring Station Structures	$ 9,301.40	23	4.35
215-M	Field Measuring Station Equipment	49,853.21	23	4.35
221-B	Field Compressing Station Structures	3,308.84	30	3.33
224-B	Field Compressing Station Equipment	15,762.02	25	4.00
	Total Other Field Facilities	$ 78,225.47		
Gasoline Investment				
900	Land (Amarillo)	$ —	—	—
902	Rights-of-Way	242.13	50	2.00
903	Structures	48,545.21	48	2.08
904	Equipment	295,099.09	28	3.57
905	Delivery Line	2,792.48	30	3.33
906	Loading Rack	3,802.16	28	3.57
	Total Gasoline Investment	$ 350,481.07		

Statement of Composite Service Lives Determined for Property of Canadian River Gas Company

Account Number and Name		Adjusted Book Cost 12-31-39	Service Life (Years)	Annual Straight Line Rate—%
Main Compressing Station (Bivins)				
218-C Land	$	1,515.66	Non-depreciable	
221-C Structures		98,770.65	50	2.00
224-C Equipment		533,487.73	35	2.86
Total Main Compressing Station	$	633,774.04		
Bivins Camp Investment				
218-BC Land	$	826.25	Non-depreciable	
223-BC Structures		163,246.08	35	2.86
227-BC Equipment		22,179.77	25	4.00
Total Bivins Camp Investment	$	186,252.10		
Transmission System				
218-D Land	$	18.00	Non-depreciable	
220-D Rights-of-Way		56,392.84	50	2.00
226-D Equipment		2,444,754.50	50	2.00
Total Transmission System	$	2,501,165.34		
Dehydration Plant (Part of Transmission System)				
218-D Land	$	441.22	Non-depreciable	
223-D Structures		6,193.62	35	2.86
227-D Equipment		35,138.83	25	4.00
Total Dehydration Plant	$	41,773.67		
Transmission Line Measuring Stations				
218-M Land	$	503.75	Non-depreciable	
222-M Structures		6,049.09	40	2.50
225-M Equipment		12,874.23	28	3.57
Total Measuring Stations	$	19,427.07		

Statement of Composite Service Lives Determined for Property of Canadian River Gas Company

Account Number and Name		Adjusted Book Cost 12-31-39	Service Life (Years)	Annual Straight Line Rate—%
General Property				
247-E	General Office Structures	$ 2,793.03	35	2.86
248-E	Other General Structures	33,588.04	35	2.86
249-E	General Office Equipment	11,735.27	12½	8.00
250-E	General Stores Equipment	6,154.19	35	2.86
255	Telephone System—Rights-of-Way	13,332.14	50	2.00
255-E	Telephone System—Equipment	73,081.00	30	3.33
256-E	General Tools and Implements	8,350.86	15	6.67
257-E	Other General Equipment	3,897.14	20	5.00
253-E	General Garage Equipment.	36,078.40	4	25.00
	Total General Property	$ 189,010.07		
Undistributed Fixed Capital				
200	Organization Expense	$ 387.45	Non-depreciable	
203	Other Undistributed Fixed Capital	8,843.16	50	2.00
	General Construction Items	2,196.01	50	2.00
262	Law Expenses During Construction	1,279.45	50	2.00
266	Interest During Construction	1,030.33	50	2.00
	Total Undistributed Fixed Capital	$ 13,736.40		
	Total Gas Plant Accounts	$ 9,923,329.94		
Miscellaneous				
100-4	Gas Plant Held for Future Use Gas Well Investment	$ 80,952.45		
107	Gas Plant Adjustments	4,091,880.88		
110	Other Physical Property	1,176.34		
	Construction Work in Progress	150,582.36		
	Total	$14,247,921.97		

Commission WITNESS HILL testified on direct examination: (Vol. L, pp. 6980-7000.)

Q. Mr. Hill, did you also in connection with this assignment prepare another exhibit entitled "Determination of Composite Service Lives for Canadian River Gas Company Property"?

A. I did.

Q. Is this the exhibit which I now show you the one which you prepared?

A. It is, yes, sir.

Mr. Lange: May the stenographer please identify it?

The Trial Examiner: It will be marked for identification as Exhibit No. 178.

(Exhibit 178, Witness Hill, marked for identification.)

By Mr. Lange:

Q. Mr. Hill, will you turn t Page 1 of the exhibit?

A. Yes, sir.

Q. Where there is a written statement prepared by you. Will you read that statement, Mr. Hill?

A. "This exhibit was prepared by me and under my direct supervision, and shows composite service lives, by accounts, applicable to the operative gas plant property of Canadian River Gas Company as of December 31, 1939. The annual straight-line depreciation rates shown in this exhibit have been determined from the composite service lives shown therein.

"In August and September 1939 an inspection of the physical plant of the company was made by Federal Power Commission engineers. Production, gathering, compressing, gasoline extraction, and transmission system property was inspected. The location, type of construction, operating conditions, degree of maintenance, exposure to weather, and other factors causing deterioration, and the extent to accrued physical depreciation and of accrued obsolescence were noted for all property inspected. The age of most of the units of property was determined from dates of installation as recorded on the books of the company. Operating and maintenance methods were observed, and operating experience was discussed with company officials and supervisory employes.

"Service lives and composite service lives have been based primarily on the physical lives of the various units of property; however, consideration was given to other causes of property retirement whenever such factors were determinative.

"Company records, from the inception of operation, were analyzed to determine the causes of all major property retirements. These included physical deterioration, caused by wear, tear, rot, rust, decay and the action of the elements; inadequacy, obsolescence; requirements of public authorities; and other causes.

"Probable future conditions of operation compared with past service conditions were considered. The probable life of the natural gas reserves and other factors which have a bearing on the probable service life of the property in each account were taken into consideration. The system was considered a continuing enterprise which will operate so long as a supply of natural gas is available. The net salvage value of the physical plant of the company at retirement is considered negligible, and no salvage value has been assigned.

"In this exhibit 'adjusted book cost' represents the legitimate original cost of gas plant as shown in reports presented in this proceeding by accounting examiners of the Federal Power Commission. 'Service Life,' as used in connection with this exhibit, means the period during which a particular unit of property is used or performs a useful function in the rendering of service. 'Composite service life' means the weighted average service life of all units of property within a primary account classification, determined by dividing the total capital in each primary account by the sum of the annuities applicable to the individual units.

"The general plan of presentation and methods that have been followed in this exhibit are as follows:

"Leaseholds (Account 205). The life of property in this account has not been determined by me and is not shown in this exhibit.

"Gas Well Construction (Account 211). The life of property in this account has not been determined by me and is not shown in this exhibit.

"Gas Well Equipment (Account 212). A composite service life of 39 years has been determined for gas well equipment. A 40-year life is deemed applicable to all wells completed by Canadian River Gas Company and affiliate predecessor owners; the adjusted book costs of such wells are their original costs. 17 wells were acquired from other companies, presumably as depreciated cost. The life applied to each of these 17 wells is 40 years, less the expired life, to the nearest whole year, at time of acquisition by Canadian River Gas Company.

"In determining service lives for gas well equipment 10 inspections of the above-ground property were made at locations picked at random throughout the field. No inspections on well casing were made as the company has had very little casing retirements.

"Factors taken into consideration in determining the service life of gas well equipment included the following:

"1. The company's experience with deterioration of well casing.

"2. Inspection of field lines.

"3. Estimates prepared by Federal Power Commission geologists as to the volume of natural gas which may be produced from the present property of the company.

"It was found that the company has had to replace well casing on some of its older wells because of casing deterioration due to various causes, but has not experienced any serious trouble to date. Our studies indicated that a reasonable physical life for the company's field lines is 50 years; in my judgment, it is reasonable to expect well casing to deteriorate at the same rate, or possibly at a more rapid rate, than the field lines which are laid in the same area. A 40-year life has been adopted as reasonable, due to the fact that well casing is subject to some hazards to which field lines are not exposed. Estimates prepared by Federal Power Commission geologists concerning the volume of gas which may be recovered from the present property of the company indicated that the gas reserves would last longer than the 40-year life adopted for gas well equipment.

"Drilling and Cleaning Equipment (Account 216). Inspections were made of some of this equipment, but informa-

tion was not compiled to determine a life. Investigation by Federal Power Commission accounting examiners revealed that depreciation of this equipment is charged directly to fixed capital and operating expense accounts. It also revealed that the balance of the equipment in this account, as of December 31, 1939, has been 88.44 per cent depreciated. Therefore, it was not considered practical nor necessary to revise the company's depreciation rate for this equipment.

"Field Lines. The property carried under this heading includes Field Line Rights of way (Account 206-B), Field Line Construction (Account 213-B), and Field Line Equipment (Account 214-B). Account 213-B includes costs incident to construction of the field lines, including labor, teaming, supervision and engineering, overheads, and other expenses. Account 214-B includes cost of pipe, couplings, fittings, valves, and other accessory equipment.

"A total of 147 inspections was made on the various field lines, each inspection representing, on the average, approximately $8,500 of investment. These inspection locations were selected by the company, with the exception of a few additional locations which were requested by engineers for the Commission. Inspections were made in August and September 1939.

"At each location selected for inspection, a section of pipe approximately 40 inches long was cleaned. The procedure followed by the Commission's engineers at each inspection was to divide a 36-inch section of clean pipe into three 12-inch sections and take 10 or more pit measurements on each section. These pit depths and the general condition of the pipe were recorded.

"In addition, if the pipe was coated, the kind and condition of coating in the adjacent uncleaned sections of the pipe were recorded; notes were also made regarding type of soil, soil hydration, drainage, the description of adjacent property. The pipe inspection data, together with calculations relating to them, an analysis of the major retirements as shown on the company's records, and other pertinent information were used as guides in arriving at a service life for field lines.

"Based on analysis of data obtained during pipe inspections and analysis of retirements since inception, a 50-year

service life is considered reasonable for the main trunk line, F-1, the investment in which is nearly half of the total investment in field lines. The same life appears to be reasonable for the gathering lines, as a group, but the company's past experience indicates that a number of the gathering lines have been relocated and that there have been substitutions of larger diameter lines for smaller diameter lines.

"It seems likely that these relocations and substitutions will continue in the future as field pressure declines. Due to these facts, a service life of 35 years is considered reasonable for the gathering lines. Using 50 years for the main trunk line, F-1, and 35 years for the remaining lines, gives a composite service life for field line equipment (Account 214-B) of 40 years.

"The same service life has been assigned to field line rights of way (Account 206-B) and field line construction (Account 213-B). Because the average life of the wells is assumed to be at least as long or longer than that of the field lines, field line construction cost has been given the same life as determined for field line equipment. Owing to the fact that field lines may not be replaced in exactly the same location, rights of way also have been assumed to have the same life as field line equipment.

"Other Field Facilities. The property carried under this heading includes field measuring station structures (Account 209-M), field measuring station equipment (Account 215-M), field compressing station structures (Account 221-B), and field compressing station equipment (Account 224-B).

"A number of detailed inspections of field measuring station structures and equipment were made. The stations inspected were picked at random throughout the field. It was found from inspection and from an examination of company records that all but one of the field measuring stations were similar, being constructed of corrugated iron on wood frame.

"The Chicago measuring station is constructed of brick. A composite service life of 23 years has been determined as applicable to Account 209-M and to Account 215-M.

"The company owns and operates one field compressing

station; this is called Field Compressing Station No. 1. The principal items of property and plant, constituting the field compressing station accounts—Structures (Account 221-B) and Equipment (Account 224-B)—as shown on the company's records, were checked and identified in the field.

"Type of construction, condition of the property, and the degree of care used in maintaining the property were observed. Three inspections were made of the underground piping at this station to determine its condition. The station is operated only a few days each month, and this fact was taken into consideration in establishing service lives. A composite service life of 30 years has been determined for structures, and a composite service life of 25 years for equipment.

"Gasoline Investment. The property carried under this heading includes Rights of way (Account 902), Gasoline Plant Structures (Account 903), Gasoline Plant Equipment (Account 904), Gasoline Delivery Line (Account 905), and Gasoline Loading Rack (Account 906).

"The principal items of property and plant as shown on the company's records were identified and inspected in the field. The service lives adopted for major equipment are based on information obtained from these inspections from analysis of company records and from manufacturers of such equipment, with consideration given to the continued technological improvements in gasoline extraction.

"A service life of 50 years has been assigned to rights of way (Account 902), 40 years having been determined as reasonable for gasoline plant structures (Account 903), 28 years for the gasoline plant equipment (Account 904), 30 years for the gasoline delivery line (Account 905), and 28 years for the gasoline loading rack (Account 906).

"Bivins Compressing Station. The property carried under this heading consists of land (Account 218), which is non-depreciable, compressing station structures (Account 221-C), and compressing station equipment (Account 224-C).

"The principal items of property and plant constituting the Bivins compressing station as shown on the company's records were checked and identified in the field. Type of construction, condition of the property, and the degree of care used in maintaining the property were observed.

"Investigation revealed that very little difficulty has been encountered with this equipment. An analysis made of engine-hours operated since installation indicates that the main compressors were operated very little during the period 1929 to 1935, inclusive, but that they have been operated regularly for the past four years.

"All of the above facts, as well as the probability of retirement due to obsolescence and to depletion of gas in the field, were taken into consideration in establishing service lives for this property. A composite service life of 50 years has been determined for compressing station structures (Account 221-C), and 35 years for compressing station equipment. (Account 224-C).

"Bivins Camp Investment. The property carried under this heading consists of land (Account 218), which is non-depreciable, other structures (Account 223-BC), and other equipment (Account 227-BC). This camp is at the same location as the Bivins Compressing Station and gasoline plant, and is used to house the personnel of both plants. The camp consists of one 16-room frame hotel, 32 frame dwellings, one frame recreation hall, four frame garages, one frame paint house, and one frame fire house.

"The same type of construction has been used for the entire camp, and it is apparent that all structures are kept in a good state of repair. The other equipment carried under this heading consists of water distribution system, electric distribution system, gas distribution system, sewer system, and miscellaneous other equipment, such as an ice plant and hotel furnishings and equipment. A composite service life of 35 years was determined for other structures (Account 223-BC), and 25 years for other equipment (Account 227-BC).

"Transmission system. This heading consists of transmission system land (Account 218-D), transmission line rights of way (Account 220-D), and transmission line equipment (Account 226-D). Transmission system land is considered non-depreciable, and rights of way have been given a service life of 50 years. A total of 120 pipe inspections was made on the main 22-inch transmission line running from the Bivins compressing station to Clayton Junction, New Mexico, and six inspections were made on the various

lateral lines, or, on the average, one inspection for approximately each $20,000 of investment. The inspection procedure described under 'field lines' was also followed in connection with transmission lines.

"Studies indicate that 50 years is a reasonable service life for pipe and equipment in the main transmission line, and 40 years for the lateral lines as a group. A service life of 30 years is considered reasonable for general emergency equipment. The aggregate book cost of the equipment with service lives of 30 and 40 years is less than 1½ per cent of the account total. A composite service life of 50 years has been determined for transmission line equipment (Account 226-D).

"Dehydration Plant. Property carried under this heading consists of land (Account 218-D), which is considered non-depreciable, structures (Account 223-D), and equipment (Account 227-D). This plant is located on the main transmission line near Hartley, Texas.

"The principal items of property and plant constituting the dehydration plant as shown on the company's records were checked and identified in the field. The type of construction, condition of the property, and the degree of care used in maintaining the property were observed. In addition to this inspection of the physical property at the plant, inquiries were made of responsible parties as to the probable service life of this type of equipment. A composite service life of 35 years was determined as reasonable for structures (Account 223-D), and 25 years for equipment (Account 227-D).

"Transmission System Measuring Stations. The property carried under this heading consists of measuring station land (Account 218-M), which is considered non-depreciable; measuring station structures (Account 222-M), and measuring station equipment (Account 225-M).

"These accounts include a main line measuring station, which measures gas delivered into the Denver line, and several smaller stations located on the various lateral lines. The principal items of property and plant constituting the above accounts as shown on the company's records were inspected and identified in the field.

"The type of construction, condition of the property, and

the degree of care used in maintaining the property were observed. All but one of these stations are similar, being constructed of corrugated iron on wood frame. The main line measuring station, located at Bivins station, is built of brick. A composite service life of 40 years has been determined for measuring station structures (Account 222-M), and 28 years for measuring station equipment (Account 225-M).

"General Property. The property carried under this heading is comprised of:

"1. General Office Structures (Account 247-E) consisting of one frame office building, located at the Bivins compressing station. The same type of construction as used in the Bivins camp was also used in this building, and it is equally well maintained. A service life of 35 years is likewise applicable to this account.

"2. Other General Structures (Account 248-E) consisting of Masterson G-2 camp and Fritch maintenance camp, Bivins Warehouse, Bivins garage and welding shop. All these structures were inspected, and it was found that the majority of this property has been kept in a good state of repair. A composite service life of 35 years is determined as reasonable for this account.

"3. General Office Equipment (Account 249-E) consists of furniture, office machines, and similar property. After giving consideration to the kind of property, its use, and to the company's past experience, $12\frac{1}{2}$ years was determined as a reasonable composite service life of equipment in this account.

"4. General Stores Equipment (Account 250-E) consisting of shelving and bins in the Bivins warehouse, pipe and casing racks, and miscellaneous equipment used for handling and storing material. A composite service life of 35 years has been determined as reasonable for this account.

"5. Telephone System (Account 255-E) consisting of telephone rights of way and telephone equipment. Telephone rights of way have been given a service life of 50 years. Telephone equipment consists of copper, copperweld, and iron wire, together with poles, brackets, crossarms, pins, insulators, guys, and miscellaneous hardware.

"The telephone system consists of lines from Bivins compressing station to Amarillo, Bivins station to Red River Gas Company at Fritch, Texas, and from Bivins station to Clayton Junction. One pole in each mile of line was carefully inspected for checks, condition of butt, and condition of treatment.

"A general inspection of the condition and type of construction of the entire line was also noted. Based on the information obtained from this inspection and the company's past experience, a composite service life of 30 years was adopted for telephone equipment.

"6. General Tools and Implements (Account 256-E) consists of miscellaneous tools, construction, and maintenance equipment. The physical life of much of this equipment is affected by deterioration with time as well as with use. A composite service life of 15 years is considered reasonable for this account.

"7. Other General Equipment (Account 257-E) consists of miscellaneous materials and equipment of many descriptions, but, since the majority of the investment represents materials and equipment with a physical life of 20 years or more, 20 years has been adopted as a reasonable composite service life for the entire account.

"8. General Garage Equipment (Account 252-E) consists of passenger cars, pickups, trucks of various capacities, trailers, tractors, and excavators. Some of this property is more in the nature of work equipment than automotive equipment. The service lives of the different types of equipment included in this account vary with the nature of the equipment and with the character and amount of its use.

"The fairest method for determining accruals for loss in the service value of this equipment is on the basis of use. However, an accurate record of use has not been maintained. In the absence of such information, loss in service value must be based on age.

"From an analysis of the experience of the company, a composite service life of four years is determined as the reasonable composite service life for this account.

"Undistributed Fixed Capital: The investment carried under this heading includes:

"1. Organization Expense (Account 200). The articles of incorporation provide for perpetual existence of the company and grant the company authority to engage in many activities in addition to its present principal functions. Due to these facts, the amounts in this account are not considered to be subject to amortization or depreciation.

"2. Other Undistributed Fixed Capital (Account 203). The analysis of this account by the Commission's accounting examiners indicates that all amounts therein represent pre-construction expenditures, which are primarily expenditures for engineering service and for reports on the feasibility of the project. A period of 50 years for amortization of these costs was determined as reasonable.

"3. General Construction Items. The amounts so designated represent adjustments in general property construction overhead. In view of the nature of the charges included in this account, it is considered that 50 years is a reasonable period over which these costs should be amortized.

"4. Law Expense During Construction (Account 262). The analysis of this account by the Commission's accounting examiners reveals that all charges included in the account represent expenditures which may reasonably be amortized over a period of 50 years from the beginning of operations.

"5. Interest During Construction (Account 266). Taking into consideration the service life of the entire system, a reasonable period of amortization for this account is 50 years."

The Trial Examiner: Does that complete your direct, Mr. Lange?

Mr. Lange: Yes, just this other:

Q. Turning to the exhibit, Mr. Hill, just following Page 15, marked "Sheet 1 of 3," the figures appearing under the first column "Adjusted Book Costs, December 31, 1939" were taken from Exhibit 146, the plant account of Canadian River Gas Company on Page 62?

A. Yes, sir.

Q. Is that correct, Mr. Hill?

A. Yes, sir.

Q. And that continues over into Sheet 2 of 3 of the same Schedule No. 1 of Exhibit 146 to Page 62, 63 and 64?

A. Well, I don't know, Mr. Lange.

Q. On the plant account of Canadian River Gas Company?

A. Yes, they are the same figures.

Q. And the service life figures under the second column, were those computed by you on the basis of the manner as outlined in the preceding pages of this exhibit in your written statement?

A. Yes, sir.

Q. And the percentages appearing in the third column were then computed by you on the basis of those service life computations?

A. Yes, sir.

Mr. Lange: I believe that is all for the present, Mr. Examiner.

Mr. Spencer: Just one or two questions, Mr. Hill.

Recross Examination.

By Mr. Spencer:

Q. Reading what you have to say on Pages 2 and 3—rather, commencing at the bottom of Page 2 and ending with the first paragraph beginning on Page 3, I assume you have not furnished any computations here with respect to property that is subject to depletion rather than depreciation?

A. No, sir, I have not.

Q. In other words, you have made no computation in connection with leaseholds or intangible well costs?

A. Absolutely.

Q. This study of yours has been confined and limited solely to depreciable property?

A. Depreciable property, yes, sir.

Q. I assume your working papers with reference to this exhibit will likewise be available to us for examination?

A. Yes, sir.

* * * * *

Mr. Hill further testified, on cross-examination: (Vol. LII; pp. 7126-7176.)

Q. Mr. Hill, I would like to ask you some additional questions this morning regarding your Exhibit No. 178 which relates to determination of composite service lives of physical properties of Canadian River Gas Company.

At least you have testified heretofore and your written statement so indicates that in determining the lives of the various classes of property owned and operated by Canadian River Gas Company you took into consideration the probable life of the natural gas reserves of the company, is that correct?

A. Yes, sir.

Q. Now, on two or three bases and perhaps more, you found the probable life of these natural gas reserves to be variable terms. The one I have a note on here is indicated as being 56 to 62 years.

A. Yes, sir.

Q. Is that correct?

A. Yes, sir.

Q. Then I believe you had a somewhat longer life on some other bases, did you not?

A. Yes, sir. The only basis that I recall putting in was 56 to 62 years according to my calculations.

Q. Well, that was the probable life that you ultimately used in making your calculations here.

A. Yes, sir.

Q. All right, now, I would like to ask you some questions about that probable life. The spread that you have there of 56 to 62 years, or a spread of eight years, is accounted for how?

A. Well, I merely took the reserve figure furnished to me by the geologists of the Federal Power Commission and then merely made estimates of withdrawals from those reserves. I took the Denver line—I put this in the record yesterday. Do you want me to put it in again?

Q. Perhaps so, because I want to go a little further with that part of it and if we have it in the record at this point it would make the succeeding answers more intelligible, I believe.

A. All right, sir. The approximate annual requirements in Mcf. at 16.4, on the basis—these are all—

Q. Does it bother you if I interrupt you? Have you—Well, strike that.

Give me the figure given to you by your engineering department. I believe it is in your written statement.

A. No, it isn't in my written statement.

Q. All right, that figure is not in your written statement?

A. No.

Q. Will you give it to me for the record the figure you obtained from the geologist department?

A. The reserve at the end of 1939 at 25-pound abandonment was 3,636,000,000 Mcf., at a base pressure of 14.65 per square inch absolute.

Q. In making your estimates, are you reconverting or are you converting again back to 16.4 pressure base?

A. I have taken the annual requirements on a 16.4 base because that is the way I could get them the nearest without converting and at the end of this I have converted back to 14.65 so it gives me nearly the same thing.

Q. So you have taken into consideration in your calculation the difference in pressure base?

A. Yes, I have.

Q. Go ahead with your explanation as to how you computed this period.

A. These will all be in Mcf. at 16.4. Approximate annual requirements Colorado Interstate Gas Company, Denver line—

Q. Will you go slow with those so that I can write them down?

A. All right. 22,000,000—

Q. Even?

A. Yes, sir, these figures have all been rounded off.

Q. All right.

A. Chicago line, the present Chicago line—

Q. Yes.

A. —22,000,000; the second Chicago line, 11,000,000; total, 55,000,000.

Amarillo Oil Company and Clayton Gas Company, 7,-000,000—

Q. All right.

A. —company use, 1,000,000; total, it being at a 16.4 base, 63,000,000; total at 14.65 base pressure, 71,000,000.

Q. I see.

A. In the remaining life from 1939, taking the figure that was furnished to me by the geologists, 3,636,000,000 Mcf. It gave me a remaining life of 51 years; the expired life, 1928 to 1939—am I going too fast for you, Mr. Spencer?

Q. Well, the 51-year life you mentioned is 51 years from 1939?

A. That is right.

Q. Now you are talking about the expired life?

A. Yes, sir, that is from 1928 to 1939—

Q. Yes.

A. —eleven years. Total life—

Q. Yes.

A. —in 1928, 62 years.

Q. I think that is good.

Now, you made some adjustments?

A. Yes, I did.

Q. Go ahead with your adjustments.

A. Stimulation due to rate reduction voluntarily or otherwise—

Q. Excuse me. Was that word "stimulation"?

A. Yes.

Q. What do you mean by that?

A. The increase in business.

Q. The increase in sales?

A. The increase in sales.

—Percentage increase, 15 per cent, is adjustment figure based upon results obtained on Denver line after reduction and space heating rates in 1934, and giving consideration to saturation of load.

Q. Saturation where, Mr. Hill?

A. Mostly in domestic gas.

Q. Geographically where?

A. Well, in the Denver area, Colorado Springs, Pueblo—

Q. Is that all?

A. Do you want domestic figures—

Q. Is that the only point you are talking about a saturation?

A. I think most of the saturation would be in the Denver area.

Q. All of the figures you have given me here are what you term approximate annual production requirements for Canadian River Gas Company?

A. That is right, they are approximate figures used in service life estimates.

Q. Now you have assumed that the annual production

requirements of Canadian River Gas Company with the adjustments which you have made for stimulation, as you call it, would remain constant over a period of 56 years?

A. Well, I don't think they remain constant, but at the time this was made these are the best figures.

Mr. March: You didn't say that they remained constant, did you?

The Witness: No, I don't think it will remain constant, but at the time these calculations were made it is the best that we had.

Mr. Spencer: I see.

Q. Before I come to that, perhaps you had better indicate for the record how you dropped down from 62 to 56 years by applying your stimulation factors.

A. All right, sir.

Colorado Interstate Gas Company, Denver line, 25,000,000—

Q. Just a minute. Let me write that down.

A. Yes.

Q. All right.

A. Present Chicago line 25,000,000—

Q. All right.

A. Second Chicago line, taken as one-half of the first, 13,000,000—

Q. Total?

A. Total, 63,000,000.

Q. Amarillo Oil and Clayton Gas Company?

A. Amarillo Oil Company and Clayton Gas Company, 8,000,000; company use, 1,000,000; total at 16.4, 72,000,000; total at 14.65 81,000,000; using the same reserve figure to cover the gas gave me a remaining life from 1939 of 45 years; expired life, 1928 to 1939, 11 years; total life from 1928, 56 years.

Q. I think that explains it, Mr. Hill. Have you ever had any experience in market forecasting?

A. I have made potential load surveys, yes, sir.

Q. For natural gas companies?

A. Yes, sir.

Q. For whom?

A. Southern Natural Gas Company?

Q. When?

A. Well, I have made them all along in town plant distribution systems from 1930 through 1937.

Q. What was the purpose of them?

A. The purpose was for installation of town plants.

Q. The size of pipe, and so forth?

A. I designed the distribution system that was to be put—

Q. You made your forecasting in connection with the construction program?

A. Yes, sir, that is right. It was a potential load survey.

Q. How did your forecasting work out, do you know?

A. Well, the forecasting—sometimes it worked out that we were low and sometimes it worked out we were high; it is just a forecast and that is all you can say for it.

Q. Do you recall the specific period for which you made those forecasts?

A. Well, we would usually make them for maybe five years in advance.

Q. Five years in advance?

A. Five years or so.

Q. Did you ever make a forecast for natural gas production 56 years before?

A. I haven't made a forecast of natural gas production for 56 years—

Mr. March: I object to the question because the question presents something that the witness never testified to. He never testified he made no forecast as to gas in this field. He got those figures from his geologist and all he knows is that his geologist gave him the figures. The geologist was on the stand and he can cross examine him on it. I move the question and answer be stricken from the record.

Mr. Spencer: I don't believe the witness answered the question. It is true, Mr. Examiner, he has used the figures here as to gas reserve that were furnished to him by the geological department of the Commission; it is also true in order to find out what the probable life of these gas reserves is—he says that he gave consideration to it and it is here in his written statement—he would have to find out or make some computation with respect to rate of withdrawals from this reserve and he has just testified at length about the figures he has for the purpose of stating withdrawals.

Now, there is no use quibbling about words; when we are talking about withdrawals here we are talking about markets. It is very important to us to know the basis upon which these withdrawals are figured over a period of years. Otherwise, this whole house of cards falls. Our depreciation and depletion rates are being figured upon this rate of withdrawal which is nothing more than markets. I think we are entitled to explore, Mr. Examiner.

The Trial Examiner: I think you are permitted to, Mr. Spencer.

Mr. Spencer: Now, the question, please, Mr. Reporter.

(The question referred to was read by the reporter, as set forth above.)

The Trial Examiner: I take it, Mr. Spencer, you referred to withdrawal forecast rather than production forecast?

Mr. Spencer: Perhaps so. I will change the question so as to make it less objectionable to counsel perhaps.

Q. We are clear, are we not, Mr. Hill, that you are talking about wtihdrawals here from the gas reserves of Canadian River Gas Company which represents its estimated annual production into the future based upon existing markets? Is that true?

A. Well, these figures that I have used were sales of gas and we have gone back on the company's records and found out what their annual requirements were and have estimated—that is, what they have been in the past and estimated these figures.

Now, if annual sales and withdrawal from the field are the same, well, I'll say yes.

Q. You have nothing here but sales except company used gas in your figures, isn't that right?

A. That is all.

Q. Well, when you get all through with your computation and arrive at 56 to 62 years, you have projected those into the future, haven't you?

A. Yes, we have.

Q. As you understand it, am I doing a violence to the English language when I call that forecasting?

A. I don't know. You can call it estimates or forecasting, either one, but I would call it estimates myself.

Q. Have you ever made any study of this nature covering a period of 56 years or 50 years?

A. I don't understand the qusetion.

Q. Have you ever made any similar study for a period of 50 or 56 years?

A. No, sir.

Q. Well, perhaps we can shorten this by asking this question: Do you consider yourself qualified and competent to forecast markets for a period of 50 years?

A. Well, I don't think I have—

Q. Now, just the question.

The Trial Examiner: You may answer it your own way, Mr. Hill.

The Witness: I don't think I have forecasted a market of 56 years, Mr. Spencer. I have merely estimated the amount of gas that would ultimately be the sales for this line. It is an estimated figure.

By Mr. Spencer:

Q. We come to this, then, that you do not pretend to say that the actual withdrawals of gas from this property by Canadian River Gas Company are going to be *anywheres* near what you have indicated here?

A. Well, I couldn't say because the figures were just what we had to determine service lives on this property and that is the only way we have used them.

Q. As a matter of fact, within five years Canadian River Gas Company may be producing and selling twice as much gas as you have indicated here?

A. If I have overlooked things that may happen, yes, sir, it will. I have taken everything into consideration that I had at the present time.

Q. Well, that is what a forecaster does. He takes all of those things into consideration.

A. I tried to—I have taken those into consideration in arriving at these figures.

Mr. March: Mr. Spencer, I think I can help you clear this up if you will let me ask a question in the record here.

Mr. Hill, as I understand, you just had the past withdrawals before you and just for the purpose of this study you assumed that—you just projected those into the future. You don't mean to state here in the record that you would attempt to state that that is what will happen in the future, do you?

The Witness: No, sir.

Mr. March: You don't make any future withdrawals—they may be double—you are familiar with the testimony—

The Witness: They may triple, I don't know. These are the best figures I had for my study.

Mr. March: You are familiar with the testimony that has been given here that there will be some increase in the withdrawals in the future?

The Witness: Yes.

Mr. March: And for the purpose of your study here you just projected this past performance in to the future but you are not stating here that that is what will happen in the future or attempting to state that that is what will happen in the future?

The Witness: No, sir, I am not. I used them for my purpose and that is all.

Mr. March: Mr. Hill, you have made no detailed study of the future requirements for Chicago or the proposed Milwaukee market drainage upon Canadian River acreage?

The Witness: No, I have not.

Mr. March: The only thing you know about that is what the company has put in evidence in this case?

The Witness: That is all.

Mr. March: And that was after you prepared this exhibit?

The Witness: Yes, sir, after I have used these figures.

By Mr. Spencer:

Q. And the company has put in no figures estimating future markets beyond 1947, is that correct?

A. As I recall it, yes, sir, it is.

Q. And in addition to the present market specified by Mr. March in his questions I assume neither have you taken into consideration any additional pipe line markets that Canadian River might have in the future? I think that follows, does it not?

A. Yes, sir, none other than this Chicago second line.

The Trial Examiner: Well, that Chicago second line, Mr. Hill, is that the line that is contemplated to include service to the City of Milwaukee?

The Witness: Well, there was two proposals in there, now. I don't know how it worked out—the Natural Gas Pipeline Company of America and I think the Western Natural or something like that, trying to get a line in.

The Trial Examiner: Just proposed a loop line initially?

The Witness: Yes, sir, as far as Natural Gas Pipeline Company of America it would be.

By Mr. Spencer:

Q. When the geological department of the Commission gave you this Canadian River Gas Company reserve figure of three trillion, six, plus, did they give you a report with it just what it represented?

A. No, sir, they just said that that was the recoverable gas under the Canadian River acreage.

Q. Did they say recoverable by whom?

A. No, sir, they did not.

Q. And you have just assumed it would all be recoverable by Canadian River Gas Company?

A. Yes, sir, that is right.

Q. You have not taken into consideration that it might be recovered by somebody else through drainage or otherwise?

A. I have made no study of that, Mr. Spencer. I wouldn't know. I just accepted these figures as they were handed to me, that's all.

Q. You just made straight mathematical calculations using the figures that they gave you, using the production figures that you have estimated?

A. Yes, sir, that is all.

Q. And arrived at a certain number of years?

A. Yes, sir, that is right.

Q. And that figure assumes that Canadian River Gas Company will recover all of the gas shown in the figure given to you by the geological department?

A. Yes, sir.

Q. You have testified regarding your natural gas pipe line experience. Have you ever had any experience in the producing of natural gas?

A. Very little, Mr. Spencer.

Q. Very little?

A. I have had some experience with it in the Monroe field but it has been limited.

Q. Did you ever supervise the drilling of wells?

A. No, sir, I have not.

Q. Did you ever supervise the gathering of natural gas?

A. No, sir.

Q. Most of your natural gas experience has been connected with the transmission and distribution end of the business, is that correct?

A. Yes, sir, most of it.

Q. Now, this figure of Canadian River gas reserves which was handed to you by the geological department is based upon a 25-pound abandonment pressure, is it not?

A. Yes, sir.

Q. Do you know anything about abandonment pressures in the gas field?

A. Well, I know that in the Monroe field the abandonment pressure there was fifty pounds.

Q. But I take it you had no experience in trying to figure out what the abandonment pressure should be, for instance?

A. No, sir, I have not made any study of that, Mr. Spencer.

Q. Well, now, let me ask you this: We have a life of 45 years, let us assume, according to your calculations, commencing August 1, 1939. Do you have any idea how many hundred wells would have to be drilled by Canadian River Gas Company in order to recover the gas that you have indicated here down to a 25-pound abandonment pressure?

A. No, sir, I do not. I have made no study on it.

Q. Well, doesn't that become of some importance and some significance in determining what your rate of depreciation should be for the well investment?

A. Well, yes, it does, and I have, as far as I could see, I have given that some consideration.

Q. Well, you can come to that in a minute. I want to follow with a couple of other questions here. Let us assume that in order to recover all of this gas down to a 25-pound abandonment pressure it became necessary for the company to drill during the last two years of the life you have indicated here, two hundred wells. Over what period and at what rate would you judge the two hundred wells should be amortized for retirement purposes?

A. Well, in the first place, I don't think they will drill two hundred wells.

Q. Well, in the first place I asked you to assume it and let's see how it develops.

A. Well, in assuming that you would take into consideration, which I have, the present wells of the Canadian River Gas Company.

Q. Do you mean to say, then, that whatever wells they may be required to drill the last few years of the life indicated by you, they will still take the composite rate for retirement purposes that you have indicated here?

A. Some of these wells, Mr. Spencer, may go twenty years, some may last sixty. This is an average life that I put on that, and over that time. I have made an estimate of the average life and I think that is a fair and reasonable figure.

Q. And the well or wells drilled by the company for the purpose of recovering the gas that you have indicated here drilled during the last two or three years would still be entitled only to a rate of 2.56 per cent?

A. This is a group depreciation rate. As I said before, some of these wells may live longer. Some may live shorter. The average life that I placed on them of 40 years will mean that you would maybe over-accrue on some of them and under-accrue on some of them, but this is the average life I have put on them, and it is a fair and reasonable life according to the knowledge that I had.

Q. I am not questioning that you haven't attempted here to be fair and reasonable. I am questioning whether or not you have taken into consideration all of the factors that you should have taken into consideration in order to arrive at the correct answer.

Now, let me ask you this: Do you know as an engineer

that the lower the abandonment pressure that you use, the greater the number of wells which would be required to take out the gas, is that correct?

A. Yes, sir.

Q. That is axiomatic almost, isn't it?

A. Yes.

Q. Don't you think as an engineer that before arriving at this composite rate of yours for our well account that it would have been advisable for you to determine the number of wells which the company would have had to drill to recover the gas down to a 25-pound abandonment pressure, and don't you think that would have given you a little better picture upon which to base your rate?

A. No, sir, I don't think so, because I am setting a service life under present conditions there and I put an average life on it and some of those present wells may live to be 60 or 70 years or they may live to be a hundred, I don't know. I placed an average life on there which I think, to my best information that I had, is a fair life.

Q. Is your average life based upon existing wells?

A. Yes, it is based on existing wells.

Q. And the number is what?

A. Number of wells?

Q. Yes.

A. 97, if I remember right, Mr. Spencer.

Q. And for the purposes of your calculation you did not need to take into consideration the number of wells and the time at which they would be required in the future?

A. Well, I have made that allowance—

Q. Was it necessary?

A. I didn't understand the question.

Mr. Spencer: Read the question, Mr. Reporter.

(The question referred to was read by the reporter as set forth above.)

The Witness: I don't think so as far as an average life or composite rates.

By Mr. Spencer:

Q. And am I correct in saying that substantially your composite rate is based upon existing wells?

A. Well, as I stated, it is an average rate.

Q. Well, you haven't—you have to have something to get an average from, Mr. Hill.

A. And it is based—some of them may live longer and some of them may live shorter, as I have stated. I have no doubt, as I say, that some of those wells might live 70 years or a hundred years, but some of them may go shorter and according to my calculations I have arrived at 40 years.

Q. All right, the point I am making is this, ~~that quite~~ aside from the physical life of these wells the company is going to have to drill wells during the latter part of this period you have indicated in order to get gas out of them, and the lives of those wells are not limited by the physical elements involved here; they are limited by these reserves which are going to play out. Did you take those wells into consideration in arriving at your average composite rate?

A. I have not determined any salvage on well casing for the Canadian River Gas Company wells drilled at a later period. Like you say, for two years before this field was depleted you should have—get your money back out of that well, that is true, but it would have a higher salvage value than was figured on present well equipment on the basis of 40 years service life.

Q. Are you familiar with a rotary drilling operation which the company now is using?

A. Yes, I have seen rotary drills work, yes, sir.

Q. How much salvage do you think there is in a rotary drilled well in the Texas Panhandle field?

A. Well, are you talking about the hole or the casing now, Mr. Spencer?

Q. When I speak of salvage I am speaking of anything that will return to the company some amount of dollars when they abandon the well.

A. They have salvage value in some casing there—

Q. Isn't it a fact that salvage value is very low on a rotary drilled well?

A. Yes, sir, it is.

Q. You say that the company now has 97 wells?

A. I think that is correct, yes, sir.

Q. Now let us assume that everything is going to work out just the way you pictured it here and that your reputation as an estimater is going to be approved one hundred per cent; that at the end of your 40 years the company has

700 wells instead of 97 wells. Would that mean anything to you in determining your average composite rates for the purposes of determining what should be done with reference to this well account?

A. No, sir, not on the present day wells.

Q. All right. One other question before I forget it. As I understand it, the Canadian River Gas Company's reserve figure of three trillion, six hundred billion is handed to you by the geological department of the Federal Power Commission?

A. Yes, sir.

Q. And then you hand it on to the accounting department?

A. Well, I think they get it from the geological department, too, just like I did.

Q. You hand it on to them in so far as it is included in your retirement rates here?

A. Yes, sir, that is right.

Q. Turn to Page 3 of your written statement. Under the heading "Gas Well Equipment," Account 212, you state that a composite service life of 39 years has been determined for gas well equipment. What classes of property have you included in that for the purposes of determining a composite rate?

A. We have included the casing and the Christmas trees.

Q. Oil well fittings?

A. That is right.

Q. The bulk of the investment would be in casing?

A. Yes, sir, I think so.

Q. The intangibles in the well you have not included?

A. I have not, no, sir.

Q. Those are subject to depletion and not depreciation?

A. Yes, sir.

Q. I believe you testified before that your study does not include any depletible property as distinguished from depreciable property?

A. I think I stated right above there, Mr. Spencer, that gas well construction was not determined by me.

Q. Now, if it wasn't for your composite rate and you were fixing an individual rate for the well equipment, you would have established a 40-year life, as I understand it?

A. Well, the 17 wells that were acquired from other com-

panies is what brought it down to 39 years, if that is what you mean.

Q. Is that what brought it down?

A. Yes, sir.

Q. Are those 17 wells that have been acquired by the Canadian River Gas Company since the beginning of its operation in 1928?

A. Well, I would have to get my working papers if you wanted to know exactly when they were acquired.

Q. It isn't that important.

You do not include in the category the wells that Canadian River Gas Company acquired from Amarillo Oil Company?

A. No, sir.

Q. Have you treated those differently?

A. I have treated the Amarillo Oil Company's wells and the wells acquired by the Canadian River Gas Company from the Amarillo Oil Company the same.

Q. The same?

A. Yes, sir.

Q. You might as well have included them in the figures you use here—I mean the figure of 17 wells—because they were acquired from another company.

A. Well, we have treated the Amarillo Oil Company as a predecessor company of Canadian River Gas Company.

Q. You have treated the wells acquired from the Amarillo Oil Company the same as the wells acquired from other companies?

A. No, sir, we presumed the wells acquired from other companies were wells that had presumably had the depreciated cost allowed for that life of the wells before they were acquired by the Canadian River Gas Company.

Q. And in the case of Amarillo Oil Company wells you have done something differently?

A. Yes, sir.

Q. That is what I wanted to bring out, that there is a distinction in your treatment of them.

Now, you say here in the determination of service lives for gas well equipment ten inspections of the above-ground property were made at locations picked at random through the field. What did you inspect, Mr. Hill?

A. We merely looked at what equipment we could see on top of the ground. We didn't inspect any casing, as cas-

ing retirements have been very light on the Canadian River's property.

Q. Have you ever had any experience before in the Texas Panhandle field?

A. No, sir, I have not.

Q. Did you examine the logs of the wells now owned and operated by Canadian River Gas Company?

A. No, sir, I did not.

Q. Do you know anything about the formations that they go through or the conditions of the holes?

A. Just a general knowledge is all I have.

Q. I believe you say that no inspections on well casing were made?

A. Yes, sir.

Q. You are not prepared to testify, then, from your knowledge of the formations in which this casing is fixed or the condition of the hole, as to what composite rate should be on gas well equipment?

A. As I say, I have just a general knowledge of the field. I have made no study. I have seen some well logs of that field but I have made no study of them.

Q. Do you know anything about the problems encountered by gas companies operated in the Texas Panhandle field with respect to the salting up of wells?

A. Well, I know that they are not troubled with salt water there. I have made inquiry into that, about the experience the company has had with wells there, and the information I received back was that they hadn't had a great deal of trouble with water encroachment and the only trouble they had had was some surface water trouble.

Q. Do you know that we do have salt formations?

A. Yes, sir.

Q. We have those?

A. Yes, sir.

Q. Do you know that the Texoma Natural Gas Company has abandoned several wells—I think seven—by reason—

Mr. March: If the Examiner please—

Mr. Spencer: Just a minute. I want to find out how much he knows here—

Mr. March: I want to state for the record, Mr. Spencer, that the questions should be directed to our geologists. Our

witness doesn't know anything about geological formations in the Texas Panhandle field, and if you insist on asking the question he can only state that he doesn't know.

The Trial Examiner: He can state whether he knows.

Mr. March: It is improper, Mr. Examiner—

Mr. Spencer: I would like to answer, Mr. March, that the only thing he has testified to so far is that he obtained from the geologist the gas reserve figures and he has taken that and then from his knowledge and experience the company, as he indicates in his own judgment as an engineer, has fixed retirement rates on this property. All I want to find out is how much he knows. If he doesn't know about it or if he got this from the geological department, he can say so.

Perhaps I had better restate the question again.

Q. Do you know that the Texoma Natural Gas Company which owns and operates gas wells in the same field has been required to plug and abandon several wells by reason of this salting condition I mentioned to you?

A. I know that they have abandoned some wells over there, but I don't know the reason for it.

Q. Do you know how many wells have been reported to the Texas Railway Commission as making salt water in the Texas Panhandle field?

A. I don't know of any of the present wells of the Canadian River Gas Company.

Q. Do you know how many in the field have been reported?

A. No, sir, I don't. I do know that the acreage of the Canadian River Gas Company is on the high part of the field. I know that.

Q. Are we speaking geologically now, Mr. Hill?

A. No, sir, I am not speaking geologically.

Q. You mean it is just the high place there?

A. Yes, sir, it is just from general knowledge and that is all.

Q. Don't you know as a matter of fact that the Canadian River Gas Company has wells that are making salt water right now?

A. Well, not from the information I had, Mr. Spencer. I can give you the information I have had if you want it.

Q. No, what I want to know is from your own information if that is not so.

A. I would like to check that if you don't mind.

Q. All right.

A. Would you like for me to read this letter from Mr. Hendee?

Q. If it answers the question it is perfectly satisfactory.

A. This is a letter written by Mr. Robert W. Hendee to Mr. J. B. O'Connor—

The Trial Examiner: What is the date of that letter, Mr. Hill?

The Witness: October 26, 1940.

"Confirming our telephone conversation this morning regarding request contained in your letter of September 23, 1940, the following is quoted from a letter which Mr. R. A. Ford wrote me some time ago:

"'Referring to your letter of the 25th enclosing copy of the letter from Mr. O'Connor asking for certain information concerning factors causing deterioration of well casing, beg to advise we have never conducted any series of tests to develop any information along the lines of the request. We are beginning to give some consideration, but to date no data has been assembled whereby it would reflect any authentic information. We have, of course, had some repair work on old wells where there had been water intrusion through pipe that had holes in it and in others where water was leaking in by the shoe but all of the well repairs have been different and we cannot assign any of the conditions he refers to in any particular wells we have worked over.'"

Mr. March: If you have no objection, Mr. Spencer, he might read Mr. O'Connor's letter so that we can tell what Mr. Hendee is talking about.

Mr. Spencer: That will be satisfactory.

Mr. March: Do you have that letter, Mr. Hill?

The Witness: I don't have a copy of it here.

Mr. March: Please get that letter later so we can have the continuity of it carried out because he is talking about

things there we wouldn't know anything about unless we had it.

The Witness: All right.

By Mr. Spencer:

Q. Did you make a study, Mr. Hill, as to the character of the 97 wells that Canadian River Gas Company now owns and operates, that is to say, whether they were rotary wells or cable tool wells?

A. I talked with Mr. R. A. Ford and from my understanding from him they use a rotary well down to what he determines the rock and then he goes to a rock outfit. That was my information from Mr. Ford.

Mr. Lange: Who is Mr. Ford.

The Witness: Mr. R. A. Ford is General Superintendent, I believe, of the Canadian River Gas Company.

By Mr. Spencer:

Q. All of the earlier wells drilled were acquired by Canadian River Gas Company, were they cable-drilled wells?

A. That is my understanding from Mr. Ford.

Q. Now, in determining your composite life here for gas well equipment, did you make any distinction between cable tool wells and rotary wells?

A. I don't think that would have any effect upon the life of the casing.

Q. You did not take it into consideration?

A. No, I did not take that into consideration.

Q. How many strings of casing do you ordinarily find down there in a cable tool hole?

A. I know back in the cable tool days that you would have maybe three or four strings of casing in there; at the present time it is my understanding from Mr. Ford that they are using entirely 8-inch casing.

Q. How many strings of casing are there in a rotary hole?

A. Well, he may use one or maybe two strings. Sometimes he may go to the bottom of the hole with 8-inch casing.

Q. Now, do you feel as an engineer that the additional strings of casing in the hole might have any bearing upon the life of the well?

A. You mean the life of the well or the life of the casing?

Q. The life of the well.

A. I am not determining the life of the well, merely the casing that is in the well is what I have set a life on.

Q. Well, if you have to abandon a well, the life of the casing has expired for the purposes of your work hasn't it?

A. Yes, we have taken that into consideration—

Q. Are you talking about the same thing? The life of the well is the life of the casing for that purpose, isn't it?

A. Read the question, please.

(The question referred to was read by the reporter, as set forth above.)

The Witness: That is, for forecasting purposes, yes, sir.

By Mr. Spencer:

Q. I mean to say this: If you have to abandon a well, you lose both the well and the casing; you are figuring no salvage value?

A. That is right.

Q. So they are the same thing?

A. Yes, sir. I figured no salvage value on it.

Q. And you do not feel that the added strings of casing in the well has any bearing upon the life of the well?

A. I think you are getting out of my line. I am not attempting to testify as to that.

Q. All right.

A. All I have figured depreciation rate on is the casing.

Q. I thought we had come to the point where the life of the well and the life of the casing were synonymous for all practical purposes to the company, at least?

A. No, sir. There might be some salvage value on casing if you abandoned a well in five, six, or two years after you put it in, but I figure no salvage value at all. In that case the life of the well would naturally be the life of the casing, and if you salvaged that casing—

Q. You think the life of the well might be longer than the life of the casing?

A. Yes, sir.

Q. Might the life of the well be shorter than the life of the casing?

A. Yes, sir.

Q. Which means nothing if you take out the factor of salvage, which you have done?

A. I haven't figured any salvage at all.

Mr. Spencer: We might take a short recess, Mr. Examiner.

The Trial Examiner: Very well, we will stand in recess for five minutes.

(At this point a short recess was taken, after which proceedings were resumed as follows:)

The Trial Examiner: The hearing will be in order.

By Mr. Spencer:

Q. Mr. Hill, I have been asking you questions concerning your knowledge of the field and well conditions of the Canadian River Gas Company. Now, I wish you would tell me as briefly as you can how you arrived at a 40-year life for gas well equipment on the Canadian River Gas Company.

A. Well, I think the method I have stated in my written statement.

Q. You mean, first you have used the company's experience with the deterioration of well casing?

A. Yes, sir, that is right.

Q. And second, you have relied upon your inspection of the field lines?

A. That was taken into consideration, yes.

Q. And third, your estimate of natural gas which will be produced in the present properties of the company?

A. Yes, sir.

Q. And in that connection you say that you have made no inspections on well casing?

A. That is right.

Q. You have made no examination of well logs?

A. No, I didn't make an examination of well logs.

Q. You have no special knowledge of the condition of the wells of Canadian River Gas Company?

A. None other than what was given me by Mr. Hendee.

Q. I would like to ask you another general question.

I take it that the life that you have found for transmission lines, namely, 50 years, is the maximum life that you use here?

A. Yes, sir, that is right.

Q. And that if the life of a well is 40 years we must assume, then, that all of the present well will have been abandoned and passed out of existence prior to the end of your 50-years, is that correct?

A. No, sir, this is an average life I have figured. Some of those wells may live to be 60 years and some may go in 30 years. This is an average life I have put in—not of the well, but on the casing.

Q. An average life for the wells?

A. For the casing.

Q. For the casing?

A. Yes, sir As I have stated in my written statement here "Gas Well Construction Cost," Account 211. "The life of property in this account has not been determined by me and is not shown in this exhibit."

Q. Well, if the average life is 40 years, then we must assume that some of these wells will have gone out of existence prior to the end of the 50-year life of the transmission line? Some of them will be gone.

A. More than likely will have.

Q. That follows, doesn't it?

A. Yes, sir. Some may go earlier and some may go later.

Q. Is it fair to say that those wells must be replaced with new wells—I mean, the wells that are going to be abandoned and will pass out of existence?

A. Well, if they are abandoned, they will have passed out of existence.

Q. The question was directed to replacement, Mr. Hill.

A. The replacement of that well will be up to the company.

Q. After all, we have to have something out of which to produce gas if we are going to have the production you have indicated here, is that not correct?

A. Well, I don't know. I haven't indicated the production. These are sales.

Q. What is the difference between sales and production as far as Canadian River?

A. I don't know whether it requires all the wells you have to produce this or not. You may be able to produce more than this on the present wells.

Q. You haven't taken into consideration the number of

wells required to produce the gas over the period which you estimate?

A. No, sir, and I don't think I would have in figuring average life, with casing.

Q. And the additional wells with casing in them or replacement wells as I have termed them before, are not taken into consideration here in your computation?

A. They are taken into consideration in so far as I have cut the life of the casing back—will you read the question, please?

(The question referred to was read by the reporter, as set forth above.)

The Witness: I don't think that would have anything to do with the life of the present casing.

By Mr. Spencer:

Q. Well, they weren't taken into consideration, then?

A. No, sir.

Q. All right. Now, you mentioned specifically here the company's experience with deterioration of well casing, and I believe in many other instances you have relied upon or at least considered the company's experience in making your calculations.

I have taken it into consideration, yes, sir.

Q. Now, what has been the length of the company's experience to date?

A. Well, you mean the Canadian River Gas Company?

Q. Yes.

A. I would say approximately eleven years.

Q. And your maximum life figure is 50 years?

A. Yes, sir.

Q. That is to say, you have only eleven years experience upon which to base an estimate for a period of 50 years, is that correct?

A. Well, as far as this company is concerned, yes, sir.

Q. As far as this company is concerned?

A. Yes, sir.

Q. And I presume it follows that if there are any errors in your calculations they will come off the last end of your term rather than the first end?

A. What was that question?

(The question referred to was read by the reporter as set forth above.)

The Witness: Well, these are all average lives, Mr. Spencer.

By Mr. Spencer:

Q. Yes.

A. And they all have a tendency to equalize themselves out.

Q. In other words, we have had eleven years experience and we have 38 years within which the errors, if any, may develop?

A. Well, these are estimates of life and—

Q. Well, I think that follows, Mr. Hill. I won't ask you—

Do you know anything, Mr. Hill, about the requirements of Texas statutes or the Texas Railroad Commission—

Mr. March: To which question we object.

The Trial Examiner: He hasn't finished the question yet, Mr. March.

Mr. March: We object to any question regarding the statutes—

Mr. Spencer: Wait a minute. I just asked him if he knew.

Before I was so interrupted, what did I say?

(The record referred to was read by the reporter, as set forth above.)

By Mr. Spencer:

Q. —relating to the production of natural gas in the state of Texas and particularly with respect to limitations upon production in connection with open flow capacity?

Mr. March: We object to that question. It is an improper question. It involves a question of statutes and is something that the witness did not have to consider in this exhibit and we don't think the witness should be required to answer it.

The Trial Examiner: He can state whether he knows.

The Witness: I know in a general way, yes, that they have proration laws in the state of Texas.

By Mr. Spencer:

Q. Now, did you take those requirements into consideration in making your calculations?

A. No, sir, I did not.

Q. Now, in your written statement under the heading "Field Line," you find that a 50-year service life is reasonable for the main trunk line? Is that correct?

A. Yes, sir.

Q. Did you make that finding because you considered it had the same permanency as transmission lines?

A. I think it has, yes, sir.

Q. In other words, you felt it was of such a character as to take the same rate as transmission lines?

A. Yes, sir, I think it is permanent. I don't think it will be moved, if that is what you mean.

Q. Well, did you find any factor that in your investigation, that would lead you to increase the life of the main field line over the transmission line?

A. No, I considered them the same, Mr. Spencer. I don't think the line will be moved.

Q. Now, do you know the wall thickness of this main field line?

A. Yes, sir.

Q. Can you give me that, please?

A. You have several different sizes and weights, Mr. Spencer. Do you want all of them?

Q. Give the wall thickness.

A. They are all the same wall thickness, 5/16ths of an inch.

Q. All right, now, will you give me the wall thickness of the transmission line of Canadian River Gas Company out of the Bivins station?

A. Three-eighths of an inch.

Q. Three-eighths?

A. Yes, sir.

Q. So we have a difference in wall thickness of how much between the transmission line and the main field line?

A. Well, that would be—

Q. One-sixteenth of an inch, isn't it?

A. One-sixteenth, yes, sir.

Q. Now, do you think that wall thickness has anything to do with the life of a piece of pipe?

A. Yes, sir.

Q. Did you take it into consideration here?

A. Yes, sir.

Q. And for the purposes of your study you find the same life for a piece of pipe with a wall thickness of 5/16ths of an inch as you do for a piece of pipe with 3/8 of an inch wall thickness?

A. No, sir, but the physical life is not determined the determined factors for the life of this pipe. It is the functional life of the field that has been given consideration in cutting the life of this pipe back to 50 years.

Q. I see. What you are expressing here in your 50 years, then, is the life of the gas reserves as you find them rather than the physical life of the pipe?

A. According to my calculations, yes, sir.

Q. I didn't get that out of your statement, Mr. Hill. I think you have answered it sufficiently, then.

For instance, on Page 5 of your written statement, the second paragraph, you state: "A 50 year service life is considered reasonable for the main trunk line F-1."

A. Yes, sir.

Q. And I certainly obtained the impression there that you were finding service life for the physical property itself without relation to gas reserves and in that I am incorrect?

A. That is not the determining factor, Mr. Spencer.

Q. Now, turn to your written statement which relates to other field facilities, and there you find a composite service life of 23 years as being applicable to the field measuring stations structures and field measuring station equipment; that is correct?

A. Yes, sir.

Q. Do you know as a matter of fact that the company has rebuilt every field measuring station that was originally constructed in 1928 as of this date?

A. I don't know that they have rebuilt them all, Mr.

Spencer. I know that they have rebuilt some houses there.

Q. Well, assume I am correct, that during the past eleven years the company has rebuilt every field measuring station that it had in 1928. Would that not indicate a life of eleven years rather than 23 years for those structures?

A. If they have all been replaced in eleven years it would, yes, sir.

Q. And in answering some of Mr. Dougherty's questions you—

A. I want to correct that last statement I made Mr. Spencer—

Q. Very well.

A. —if you don't mind. That would not be the life of eleven years because we figured this on an average life basis and it may be that some of them would go out in five years and some of them might last longer, because all the lives that we have figured have been on an average life basis.

Q. All right. If we have had to rebuild every one of them that we had in 1928 in eleven years, and you arrive at a composite service life of 23 years, it looks to me like you are going to have to build some brick houses or something in order to raise that average up to 23.

A. Taking into consideration the brick meter stations on the Chicago line that is included in this account is what runs the composite of this account up a little.

Q. Are you familiar with corrugated iron structures in the Texas Panhandle field?

A. Well, I am familiar with corrugated iron structures. As I stated before, I have not had a lot of experience in the Panhandle field.

Q. Well, they are a little different in the Texas Panhandle field. In riding along the highways of the Texas Panhandle field, did you notice the corrugated iron strung all along the highway, pieces of it all wound up here and there?

A. Yes, sir, I have noticed some of it.

Q. Where did you think that same from?

A. I have no idea.

Q. It may be very dry in the Texas Panhandle field, but they also have wind and sand to contend with, too, do they not?

A. Yes, sir.

Q. From the evidence you see over the terrain, this wind perhaps has something to do with the tearing these corrugated iron structures, does it not?

A. Well, they may blow off a sheet, but that is a maintenance job to put it back.

Mr. March: It doesn't destroy the iron, does it—the wind?

The Witness: Well, it might bend it up, but that is a maintenance job.

Mr. March: There would still be some sort of salvage to that, wouldn't there?

The Witness: I don't think so.

Mr. Spencer: You can have it.

Mr. March: It must be in awful fine pieces.

By Mr. Spencer:

Q. Well, one brick structure you say raised the composite rate which you found?

A. Yes, sir.

Q. How many other field measuring stations are there?

A. Well, I would have to go back in my working papers.

Q. About the same number of field measuring stations as there are wells?

A. Approximately, yes. There are some additional measuring stations, of course the measuring station on the gas to Amarillo Oil, that was taken into consideration, too. I would have to go back to my working papers.

Q. You have one brick structure and ninety some corrugated iron structures, is that not true?

A. I wouldn't want to state until I had my working papers to check it.

Q. We have ninety some wells, do we not?

A. Yes, sir.

Q. We have one of those structures at about every well, do we not?

A. I think so, and also measuring gas to the Amarillo Oil Company. I might have that number here.

The Trial Examiner: What rate did you put on the

galvanized iron structures, Mr. Hill, or did you put any specific rate on those structures?

The Witness: It was all figured in a composite rate. I have placed 20 years on them. That is figured in the composite.

By Mr. Spencer:

Q. 20 years for corrugated iron structures?

A. Yes, sir, on a wood frame.

Q. Now, turn to Page 10, Mr. Hill, of your written statement, that paragraph which is headed "Dehydration Plant." You find the composite service life of 25 years for dehydration plant equipment, did you not?

A. Yes, sir.

Q. To what extent did you consider obsolescence in fixing that rate?

A. Well, I considered—in fact, I talked with people that were familiar with this property and—

Q. I believe you mention in your statement, inquiries were made of responsible parties?

A. Yes, sir.

Q. Who were they?

A. Stearns-Roger Manufacturing Company.

Q. Denver, Colorado?

A. Yes, sir.

Q. And is your rate here based upon what they told you or is it based upon your own judgment?

A. My rate is lower than what they told me, Mr. Spencer.

Q. Well, is it based upon your judgment or—

A. Yes, sir, entirely on my judgment. I just merely used that as a guide to get all the information. The plants are relatively young and there has not been a great deal of experience with them.

Q. Would you consider that the company has a modern plant; that is to say, a plant that has the benefits and advantages of all recent improvements and inventions for dehydration of gas?

A. Well, if that is all you want to do, I would say yes it is. Of course, there are better systems, but I don't think that Canadian River Gas Company will abandon this dehydration plant to put in one just because of a different design. I don't think that.

Q. There are better systems?

A. I think the Glycol system is a better system. That is my own opinion.

Q. What is the chemical they use here for dehydration medium?

A. They use some type of—not being a chemist, I can't carry these things in my mind—some sort of sodium chloride or hypochlorite or something like that.

Q. Any time I get out of your field, you just say so. Do you know whether or not that is highly corrosive chemical.

A. It is corrosive with the presence of free oxygen, which you shouldn't have in this plant.

Q. That would be one factor that you would have to look at in determining the life of this particular plant?

A. Well, according to the best information that I have, as long as there is absence of free oxygen, it is not very corrosive. That is my information.

Q. Do you know as a matter of fact, that the piping in the brine storage tank at this plant was completely replaced in a period of three years?

A. Yes, sir. I know that there has been some replacements there and that is the reason I have cut this life back to 25 years. The majority of your investment is not in the brine storage tank.

Q. Well, would you consider replacement of piping in the brine storage tank to be maintenance, then?

A. Well, I adhered to the retirement units shown in the appendix of the classification of accounts, and that would govern that as far as I am concerned.

Q. I am talking only about replacements of these particular items of property.

A. If it was a unit within itself it would be a replacement unit, yes, sir.

Q. And it would not be considered as maintenance by you for the purpose of your study here?

A. No, sir.

Q. It would not?

A. If it was an entire unit that you took out.

Q. But you do know that this particular part of the dehydration plant required replacement in three years? You are aware of that fact?

A. Yes, sir. It is a very minor part of the whole plant, though, Mr. Spencer.

Q. Now, in making your determination of service lives as contained in this study, Exhibit 178, did you give any consideration to service lives as used by the company for income tax purposes?

A. No, sir.

Q. Did you find out that in the course of your examination that engineers for the Bureau of Internal Revenue has made an investigation of this same subject matter?

A. I understand they have, yes, sir.

Q. Did you find out the results of their study?

A. I know the depreciation rates the company is using, yes, sir.

Q. But you gave no consideration to that here?

A. Not in determining my service lives, no, sir.

Q. In making your determinations of service lives here, did you give any consideration to the lives of the principal contracts under which the company operates?

A. No, sir, I gave no consideration,—if you are speaking of contracts between the Colorado Interstate Gas Company and the Canadian River Gas Company, I gave no consideration to that.

Q. Nor to the contracts between Colorado Interstate Gas Company and the Public Service Company of Colorado?

A. No, sir, I have no reason to—

Q. Well, whatever you have done here is without regard to those contracts?

A. Yes, sir.

Q. Or any terms fixed therein?

A. Absolutely. That is right.

Mr. Hill also testified in connection with this subject under title 27 supra.

The determination of the necessary annual allowances for depreciation and depletion on a regulatory rate basis during the period January 31, 1939, to December 3, 1956, is contained in Exhibits 276 and 277, Witness Lusk, and is abstracted infra. Mr. Lusk in those exhibits, in using the period mentioned, adopted the testimony of the Witness Hendee, General Manager of respondent (Exhibit 255).

showing that the economic life of the field would cease by the end of 1956, and he also used the sinking fund method, with interest at $2\frac{3}{4}\%$.

The Commission also presented Exhibit 190 setting forth an alternate method of accruing depletion. Mr. Luttring testified in connection with this exhibit as follows: (Vol. LVIII, pp. 8253-8267.)

Direct Examination.

By Mr. Lange:

Q. You are the same Carl E. Luttring that has heretofore testified in these proceedings?

A. I am.

5 Q. Mr. Luttring, I will ask you whether in connection with your work you have prepared another exhibit in connection with the Canadian River Gas Company matter that would give effect to an alternative method of accruing annual and accrued depletion of gas well intangible costs?

A. I have.

Q. Is this the exhibit prepared by you?

A. Yes, sir, it is.

Mr. Lange: May the stenographer mark it for identification?

The Trial Examiner: It will be marked for identification as Exhibit No. 190.

(Exhibit 190, Witness Luttring, marked for identification.)

By Mr. Lange:

Q. Now, Mr. Luttring, in connection with the preparation of that exhibit did you also prepare a written statement summarizing the main portions of the exhibit and explaining it?

A. I have, yes, sir.

Q. Will you proceed to read that written statement into the record?

A. "The purpose of this supplementary report is to reflect in the balance sheet at December 31, 1939, and income and earned surplus account of Canadian River Gas Company for the year ended that date, the effect of depletion of well construction costs as determined in accordance with the alternative method proposed by the Division of Gas

Engineering. The following schedules which form this report reflect the effect of the depletion computed pursuant to the alternative method:

"Schedule No. 1 Condensed Income and Earned Surplus Account As Adjusted for the Year Ended December 31, 1939, Giving Effect to Alternative Depletion as Proposed by Supplemental Entry.

"Schedule No. 2 Balance Sheet As Adjusted December 31, 1939, Giving Effect to Alternative Depletion as Proposed by Supplemental Entry.

"Schedule No. 3 Examiner's Supplemental Entry to Give Effect to Alternative Method of Accruing Depletion of Gas Well Intangible Costs as Proposed by the Division of Gas Engineering.

"Schedule No. 4 Summary of Annual and Accrued Depletion and Depreciation of Gas Plant in Service at December 31, 1939, After Giving Effect to Alternative Depletion as Proposed by Division of Gas Engineering.

"The exhibit already presented on annual and accrued depletion and depreciation reflects annual depletion of well construction costs based on the recoverable gas reserves under all of the leases of Canadian River Gas Company. The company used the same method in its determination of annual and accrued depletion. Under this method the Mcf. unit cost of depletion increases with the construction costs of each new well added to the depletable base.

"The Division of Gas Engineering in the alternative method proposes that annual and accrued depletion of well intangible construction costs be depleted on the basis of recoverable gas reserves under the producing gas wells as of the beginning of each accounting period. Under this method the Mcf. unit cost of depletion tends to remain more nearly constant. Schedule No. 4, Column 4, shows the annual and accrued depletion resulting from the alternative method of computing depletion of well intangible costs.

"The alternative method, as computed in Schedule No. 3, results in total annual depletion in the amount of $324,884.26 as compared with $172,929.56 under the method already presented, or an increase of $151,954.70 for the period from June 1, 1928 to December 31, 1939.

"The increase of $151,954.70 in annual depletion is reflected in Schedule No. 1 in the following manner:

"Increase in 1939 operating revenue deductions	$ 13,286.48
"Decrease in earned surplus account at January 1, 1939, representing additional annual depletion from June 1, 1928 to December 31, 1938, inclusive	138,668.22
"Total	$151,954.70

"The accrued depletion at December 31, 1939, as is shown in Schedule No. 2 was increased by the amount of $151,954.70, representing the total additional annual depletion produced by the alternative method.

"The assets and other debits and liabilities and other credits at December 31, 1939, as adjusted, as stated in Schedule No. 2, and income and earned surplus for the year ended December 31, 1939, as adjusted, as stated in Schedule No. 1 represent the balances which appeared in the following reports presented by Examiner L. B. McKinstry:

"Balance sheet and supplemental data

"Income accounts and supplemental data including Examiner's reclassifications and adjustments

"Depletion of intangible well construction costs based on the recoverable gas reserves under all of the leases of Canadian River Gas Company or depletion of intangible well construction costs based on the recoverable gas reserves under the producing gas wells each have merit and either will provide a reserve at the expiration of the gas reserves sufficient to retire the related investment.

"The principal difference is that the depletion of intangible well construction costs based on the recoverable gas reserves under the producing wells provides a larger reserve as of December 31, 1939 and will provide larger annual amounts for the next several years, depending upon the company's drilling program. Additional expenditures of approximately $1,000,000 would be required before either method would produce the same amount of annual depletion. The alternative method will meet the requirements

of accepted accounting practice and is also being presented to the Commission for its consideration in these proceedings."

Q. You have completed your statement, Mr. Luttring?

A. I have.

Q. Turn back to it again, in order that it may be more complete and tied in with the other exhibit referred to, on Page 1 of the written statement at the bottom, the last paragraph on the page, the exhibit reads: "The exhibit already presented on annual and accrued depletion and depreciation * * *" that is Exhibit 176 heretofore presented in evidence, was prepared by Mr. Kenneth L. Smith and yourself, isn't that correct?

A. Yes, sir.

Q. Turn to the last page of the written statement. At the top of the page where you refer to the balance sheet and supplemental data, that is Exhibit No. 169 heretofore presented in evidence in these proceedings?

A. That is correct.

Q. And the income accounts and supplemental data including Examiner's reclassifications and adjustments have been presented here as Exhibit No. 168?

A. That is correct.

Mr. Lange: That is all for the present.

Cross Examination.

By Mr. Spencer:

Q. Now, Mr. Luttring, turning to your written statement here, the first sentence on the first page, in it you state that what you have done here is to give effect to depletion of well construction costs as determined in accordance with the alternative method proposed by the Division of Gas Engineering?

A. That is correct.

Q. Your Exhibit 176, I assume, was the first method that you employed for this purpose?

A. That is right, and that method is very similar to the one that the company is now using.

Q. Yes.

Mr. Lange: The one set up in Exhibit No. 176?

The Witness: That is correct.

By Mr. Spencer:

Q. Before I go any further, the principal difference here is in the one case we are depleting against total recoverable reserves, and in the other case we are depleting against recoverable gas allocable to producing wells?

A. That is correct. In Exhibit 190, of which we are talking about here, you have depletion on a basis of reserves which are in place under the existing wells.

Q. Now, the first method that you used in Exhibit 176 was a method that was also proposed by the Division of Gas Engineering, I assume?

A. No, sir.

Q. They did not propose that method?

A. No, sir.

Q. Where did you get that method?

A. The method, as I explained in Exhibit 176, you might say was identical to the one which the company is now using. The only difference was the amount of reserves which we used in our calculations.

Q. Did you adopt that method in Exhibit 176 because it had been followed by the company or for some other reason?

A. Principally because the company was using it.

Q. Is it a method that is generally practiced by gas companies?

A. Yes, the basic factors used in it are quite similar to all methods of that form of depletion.

Q. When you used your first method which follows very closely what the company is now using, you did that based wholly upon your own judgment?

A. Yes.

Q. You received no instructions to do that from anyone?

A. No, sir.

Q. Now, in this case you have presented an exhibit here to carry out an alternative method which has been proposed by the Division of Gas Engineering?

A. That is correct.

Mr. Spencer: Now, I don't want to get ahead of the story here, but is this method to be supported by the Division of Gas Engineering or do I get it from the witness on cross examination, or how is it to be handled?

Mr. March: Let the witness explain it.

Mr. Spencer: All right.

The Witness: We can only go this far, that the gas reserves that were used under the existing wells at December 31, 1939, that information was furnished to us by the Division of Gas Engineering. The reserves that were under the existing wells at the dates ending December 31st for the years prior to December 31, 1939, were also supplied to us by the Division of Gas Engineering.

Mr. Lange: They will be here ready to support that?

The Witness: I think that has already been introduced in Exhibit 181 by Mr. Stevens.

Mr. March: That is the reserves of the well and the others are the reserves on leases, that exhibit being prepared by Mr. Hammer. As far as the reserve figures are concerned, they were furnished to the accountants, the reserves under wells and the reserves under leases. They just used those reserve figures, but their application is their own—

Mr. Spencer: Quit testifying, Mr. March.

Mr. March: Is that correct, Mr. Luttring?

The Witness: Yes, that is correct.

Mr. Spencer: All I wanted to know was where to go and get the facts. That may be right, Mr. Luttring.

Q. I can get all of my facts and data from Mr. Stevens' Exhibit 181 that I need to check the computations which you made in Exhibit 190, is that correct?

A. That is correct. They would either come out of Exhibit 181 or his working papers.

Q. Mr. Stevens has let me have his working papers and we will try to check the figures from what we have.

What working papers do you have, Mr. Luttring?

A. The working papers which I have would be exactly similar to this Exhibit 190.

Q. Do you mean you would hand me a copy of Exhibit 190 for your working papers?

A. It would be a rough draft of this particular exhibit.

Q. I won't go into the particulars of your calculations at this time, Mr. Luttring, until we have checked with Mr.

Stevens' Exhibit No. 181 and his working papers to see if we have the necessary data upon which to check it. However, I do have a few general questions I would like to ask you.

At whose request did you make this particular exhibit?

A. I can't tell specifically. I do have some letters in the files that originated with the Bureau of Gas Engineering of the Federal Power Commission. Possibly Mr. Stevens would be able to enlighten you specifically on that matter.

Q. Well, for the moment I am interested in this: This is purely with reference to your functions in the matter: You have already prepared an exhibit here which contains a specific method for computing depletion and that method and your computations have been carried into a great many other exhibits which follow. I am wondering why the alternative method at this time—I wonder if you were dissatisfied with the method you used in the first instance and thought something else should be done about it.

A. No, we were not dissatisfied with the depletion as computed under Exhibit No. 176. In the first place we wanted to complete our schedule and at that time I don't think this information was quite available.

Mr. March: May I ask a question there, Mr. Spencer?

Mr. Spencer: Surely.

Mr. March: As a matter of fact, Mr. Luttring, it was determined by your superiors that both methods would be used and the Commission would be given the benefit of both calculations and they could choose which one they wanted?

The Witness: I think that is correct.

Mr. March: Doesn't that clear it up?

Mr. Spencer: I think so.

Q. You had no function here except to mechanically carry out something that was handed to you?

A. That is correct. As I say, it originated—.

Q. You exercised no judgment—you didn't initiate any judgment in carrying out a policy or program outlined by someone else?

A. Only to this extent, that we did feel that this particular method was practical from an accounting standpoint.

Q. You placed your approval on it from an accounting standpoint?

A. That is correct.

Q. Does the Bureau of Internal Revenue recognize this particular method for the purpose of computing income taxes?

A. I am sure they do.

Q. Do they?

A. That I don't know.

Q. On the second line, Page 1 of your written statement, Exhibit 190, you refer to the balance sheet of the company at December 31, 1939. I assume that balance sheet is after the multitudinous adjustments that have been made in it by the Commission, or is that per company books?

A. The balance sheet would be as adjusted and as shown in Exhibit No. 169 is our starting point. Exhibit No. 169—

Q. That is the balance sheet you are using as a starting point?

A. Yes, sir.

Q. All right, I have that. That is as adjusted, is it not?

A. That is as adjusted.

Q. That is all I need on that.

The first paragraph commencing on Page 2 of your written statement, the second sentence, states: "Under this method the Mcf. unit cost for depletion tends to remain more nearly constant." That is correct?

A. That is correct.

Q. That is your statement, is it not?

A. That is correct.

Q. Are you intending thereby to place your stamp of approval on the method?

A. No, I am merely stating a fact.

Q. Are you intending thereby to express any preference between methods?

A. No, sir, I have not.

Q. Have you any preference as between the two methods?

A. I would have if I had to make a choice.

The Trial Examiner: Mr. Luttring, that is just what the Examiner is going to be faced with and I would very much appreciate your expression as an accountant as to which method you feel is a preferable one.

Mr. March: Only with this observation: Of course this observation—we don't object to the asking of questions of this witness but it does involve some engineering matters. For example, here is the thing involved. You have a lease and some wells on the lease. The difference here is in one case he has depleted the reserves under leases and in the other case the reserves under wells. It brings in an engineering question as to whether or not the present reserves could be depleted by those present wells. We don't object to him answering the question as long as there is no engineering matter in there. That is the whole heart of the thing. It really comes down to the engineering proposition as to whether or not the user is depleting the wells over a period of years. You are going to do it by the reserves under the wells or the reserves under leases. It is well known that it is an engineering question as to whether or not present wells could draw all of that gas out of those leases and we are depleting wells here; we are not depleting leases, and so there you are. It does bring in the basic engineering question but we don't have any objection to this witness answering this thing from an accounting standpoint with that observation.

Mr. Spencer: I am not going to ask him any engineering questions and I am not going to ask him to commit the Commission, which he wouldn't do in any event. I am merely asking him as an accountant whether he has a personal opinion—

Mr. March: You mean preference.

Mr. Spencer: A personal preference between the two methods, and I believe he said that he did have a choice.

The Witness: I would prefer using the alternative method.

By Mr. Spencer:

Q. The method in Exhibit 190?

A. Yes, for the reason that the expenses from year to year would be slightly more accurate.

Q. Well, you mean they would be more constant or more stabilized?

A. That is right.

Commission Witness Stevens testified on cross-examination and redirect examination: (Vol. LXIII, pp. 9016-9042.)

Q. Do you have a copy of Exhibit 190 there, Mr. Stevens?

A. 190?

Q. Yes.

A. No, sir, I don't.

(The document referred to was passed to the witness.)

The Witness: Schedule 5, I believe it is, Mr. Spencer Is that right?

By Mr. Spencer:

Q. Yes, that's right. Now, Mr. Stevens, in his written statement regarding Exhibit 190, Mr. Luttring said:

"The purpose of this supplementary report is to reflect in the balance sheet at December 31, 1939, and income and earned surplus account of Canadian River Gas Company for the year ended that date, the effect of depletion of well construction costs as determined in accordance with the alternative method proposed by the Division of Gas Engineering."

Is he referring there to your proposal?

A. Yes.

Q. Now, was your proposal made in writing of some character?

A. I don't recall. Except to state these figures shown in Column 2 on Schedule 5. Mr. Luttring could perhaps answer that point a little more accurately.

Q. But I must ask you what your proposal was, Mr. Stevens.

A. I didn't write any letter, if that answers your question more specifically.

Q. Well, what did you propose?

A. Simply these figures as representing the gas reserves—recoverable gas reserves in place at the ends of those years, that is all.

Q. That means you merely supplied data?

A. That is the fact of the case.

Q. Well, then, is it true to say that you made no proposal to the accounting department of the Commission?

A. Verbally I believe—

Mr. Spencer: I don't want to follow this thing around if we can get somebody to say when it was done and why it was done.

Mr. March: He is going to answer.

The Witness: Before we came out here to Denver this figure was requested—I say "figure"—in its multiple aspects, reserves as of the ends of various years, and we supplied that.

By Mr. Spencer:

Q. The figure was requested by whom, Mr. Stevens?
A. I don't know who made the original request.
Q. What department?

Mr. March: I will state this for the record so there won't be any difficulty. All requests of the Federal Power Commission as far as divisions are concerned come through the Bureau Chiefs. Now, Mr. Stevens was given an assignment. He was given this assignment to prepare this exhibit to show what the remaining gas reserves—or the remaining gas you would get out using just the present wells. We will stipulate to that as far as that goes.

By Mr. Spencer:

Q. Well, who made the proposal referred to here as having been made by the Division of Gas Engineering to suggest an alternative method of figuring depletion on intangible well costs?

The Trial Examiner: Mr. Stevens just testified that that was his proposal.

Mr. Spencer: That is one of the first questions he answered in the affirmative.

Mr. March: He furnished the figures, Mr. Examiner.

The Trial Examiner: Perhaps he wants to change the answer, but that is the answer he made.

Mr. March: He said he furnished the proposal in so far as he furnished the data. He furnished just the data.

The Trial Examiner: Maybe he misunderstood Mr. Spencer's question, but that isn't what he said.

The Witness:- I think the interpretation of the word "proposal" at the instant it was mentioned, our interpretations may not have been exactly the same: I have nothing to hold back on this. I would like to state an exact answer to your question but the fact is that this request for these reserves as of these years came through, I suppose, approximately the channel that Mr. March stated.

Now, as to having a part of the proposal, I recall that we were—several of us, including Mr. Luttring and Mr. Hamner and myself, discussing the use of these figures and the element of proposal was rather minor, Mr. Spencer. We thought that this reserve figure as calculated here for the various years back to 1928 was a reasonable figure in terms of this kind of an exhibit. I am not an accountant myself and it was not made up from any accounting standpoint. It was simply stated as what we considered to be a reasonable way to do it and in so stating there was no competition, you might call it, between the accountants and us as to what should be used or what had to be used. It was merely a suggestion more than a proposal, and they worked up this exhibit incorporating those figures and that is the extent of the proposal. It was more a suggestion and discussion rather than a strong proposal. It certainly wasn't a strong proposal. It was simply our idea of one way to do this.

By Mr. Spencer:

Q. Well, you didn't propose to Mr. Luttring or anybody in the accounting department to go ahead and us this data for the purpose of compiling Exhibit 190?

A. Well, in the sense that a suggestion is a proposal, it is a proposal as he states. It hinges apparently around the exact definition here of the word "proposal." I believe that states the facts of the case as much as I know them.

Q. Well, maybe they will become more apparent as we go along, what I have in mind.

About when did you receive your request or your instructions to compile these figures that have been used in Exhibit 190?

A. I don't recall that date. I believe it was in August or September. I am not sure.

Q. Of last year?

A. Yes, 1940.

Q. That was prior to the time that you had prepared Exhibit No. 182, your exhibit?

A. No, that wasn't prior to the time that that was completed. As I recall, the Exhibit 182 was completed just prior to supplying the accountants with these figures. They are more or less the conclusion of Exhibit 182, and the completion of these occurred approximately at the same time. I know that Exhibit 182 had not been done long.

Q. Now turning to Page 5 of Exhibit No. 190 which is sheet 2 of 2, Schedule No. 3, there are five columns in the schedule at the top of that page. Will you point out the schedule, or the column that contains data furnished by you?

A. It should be explained I think here at this point that where we considered reserves as of the end of one year, Mr. Luttring apparently has used that same reserve as being the beginning of the following year which is the same thing.

Q. May I stop you there? I mean, as I understood it over here, you calculated reserves in the middle of the year—

A. The figures were as of the ends of years, Mr. Spencer.

Q. These figures over here in 190?

A. Yes. You see that 2238 at the bottom of Column 2?

Q. Sir?

A. You see the 2238 at the bottom of Column 2?

Q. Yes.

A. That is the gas reserves as of 1940. He means the beginning of 1940 and I stated it as of the end of 1939. That is the point I just mentioned. Look on the last page of my written statement.

Q. I am trying to tie that statement into Exhibit 182.

A. You will see on the last page of my written statement, Mr. Spencer, not the tabulation, just the last typewritten page.

Mr. Lange: Of your Exhibit 182?

The Witness: 182, yes.

Mr. Spencer: Yes.

The Witness: See that 2238 as being the reserve?

By Mr. Spencer:

Q. That's right, I see.

A. The difference is that he calls it the beginning of 1940, which as I said, is the same thing.

Q. Yes, I understand that. Now, go ahead with the designation by columns of data that you furnished for this schedule, Page 5, Exhibit 190.

A At this point it is necessary to make another explanation. You see the figure for the beginning of 1939 of 2,285,632,410,000?

Q. Yes.

A. That is the reserve as of the beginning of 1939 inclusive of production figures I actually supplied him excluding production. That is the difference between the figures I supplied Mr. Luttring and the ones he shows here. It is necessary to make that explanation and involves the point of view of the accountants as to whatever they used it for, which was depreciation, I believe.

Q. Depletion?

A. As I understand it, the reason it was necessary to divide this into money before production was taken out was in order to determine the rate of per Mcf, which was shown in Column 5. That is the character of this work that made it desirable to do that; and that is the only point of difference between the figures I actually gave him and the figures he uses here.

It is further stated that these figures are based on the figures that I did actually supply.

Q. Well, you haven't quite answered my question, Mr. Stevens, as you got off on another explanation. What you did furnish for Mr. Luttring on Page 5 of Exhibit 190, his exhibit, was the gas reserves shown in Column 2 with the explanation that you have made?

A. With the explanation I have made. I might make it a bit simpler by saying this: The figures Mr. Luttring shows in Column 2 are the ones I gave him but including production for the year in question and that is the difference.

Q. You also furnished him, I take it, with the annual production figures in Column 3?

A. I don't recall whether we did or not. Did he say so?

Mr. Spencer: May Mr. Luttring answer that question from where he is?

Mr. March: Just a moment. There is a way to do this.

This witness can tell, Mr. Examiner, every figure he furnished here, but as to tell how and why Mr. Luttring uses these figures, that is Mr. Luttring's obligation.

Mr. Spencer: I haven't asked him how they were used. I am asking him what was furnished.

The Trial Examiner: He hasn't been asked how.

The Witness: That can be stated very simply. It is the reserve figures for the end of the year 1939 backwards to 1928 to which he added production for the years in question to arrive at the figures shown in Column 2 for the reason explained; and if that reason isn't explained enough I think Mr. Luttring can explain that better because he is an accountant.

By Mr. Spencer:

Q. It is perfectly clear to me, Mr. Stevens. There is no complication about it except in Mr. March's mind. I am clear on it. All I want to know is, did you furnish any production figures or did Mr. Luttring get them some place else?

A. I don't recall whether he did or did not, or whether that was supplied by the Denver office.

Q. Have you figures in your working papers you could spot check to see whether they agree with your production figures?

A. Yes.

Mr. Lange: Mr. Spencer, you are referring to the figures in Column 3, Page 5, Exhibit 190?

Mr. Spencer: Yes.

Mr. March: Did he testify he didn't furnish the figures?

The Trial Eaxminer: He is testifying that he is trying to find out.

The Witness: I have them here, Mr. Spencer.

By Mr. Spencer:

Q. Don't check them all. Just spot them.

A. I am doing that. So far they do check.

Yes, they are the same and it is possible that we supplied them, although I am not sure on that point.

Q. I think you did but it doesn't make any difference particularly.

Now, Mr. Stevens, correct me if I am wrong, but I understood from your cross examination by Mr. Keffer that through the calculations and computations made in your Exhibit 182 you arrived at a reserve figure for the end of 1939, did you not?

A. Yes, sir.

Q. And that figure is what?

A. 2,238,849,016.

Q. Which is shown here as you have explained it as being at the beginning of 1940?

A. He has so designated it.

Q. Now, in arriving at your reserve for prior years as I understand it you figured backwards from your 1939 figure?

A. Yes.

Q. Tell me how you did that, just generally. Make it as simple as you can.

A. Well, I believe that if I read this statement which consists of a few notes of consecutive calculations that it would clarify it probably better than picking my way back out. Is that satisfactory?

Q. Go ahead.

A. Method of calculation of future expectancy for December 31st of any given year—1929 is used as an example.

The Trial Examiner: 1929?

The Witness: 1929. We could have used 1939. You can look at it going ahead or looking backwards in time in figuring it out.

1939 is the year I started. It is possible, however, in this note—I say it is possible because it was a reverse of the preceding discussion, but starting with 1939, if that makes it simpler, it is also possible to use the expectancy of 12-31-39 as a starting point to work back to 1928 by years by reversing the procedure that would be followed if they were calculated from 1928 forward.

Adopting the reverse procedure, all columns are avail-

able as basic data except Columns 7 and 8 and Column 7 and 8 on—

Mr. Spencer: Wait a minute, Mr. Stevens. Let's identify the columns you are talking about.

The Witness: They are not anything you have there. It is my working sheet. I was going to name them, except the expectancy of the start of the year including production of all wells—I believe that is the only thing it does not include.

We have the expectancy of 12-31-39 of 2,238,849,016 cubic feet. Now the production for 1939 of all wells is then added because to get back to the beginning of 1939 it is necessary to add the production of 1939. That production, to simplify the description can be considered as negative expectancy or expectancy that has been used up in the form of production.

By Mr. Spencer:

Q. I thought we were going backward instead of forwards.

A. Yes. By adding production you get back to the expectancy it was at the beginning of the year.

Q. Go ahead.

A. And that comes to the figure of 2,285,632,410,000 cubic feet. That, you see, is a figure that Mr. Luttring uses. The difference between my figures and his is that he includes that production and considers the expectancy to have been brought in at the beginning of the year and to serve as a basis for calculations of the latter part in the columns in his Schedule 5.

From this figure we must subtract the expectancy of the five wells that were drilled in 1939 to get back into the previous year for the reason that at a certain point those wells that were drilled had no expectancy whatever.

We must also subtract their production. This figure amounts to 123,479,112,000 cubic feet.

Q. What does that make for the well, approximately? Is that your same 24 billion figure, approximately?

A. 124?

Q. I asked you what the average was per well. Then I asked you if that was the same 24 billion used for adding wells in 1940.

A. That is right. These expectancy figures, the calculations you will note in all cases with regard to previous years, the expectancy figure calculations start as of 1939 and that average is used to go backwards in this case.

Q. The same average throughout?

A. Yes, because it is all as of the date of 12-31-39.

By the way, it isn't 24. At the end of 12-31-39 it is 23 something. It is 23,817,543,000. At the end of 1939 the average expectancy is, of course, less than at the middle of 1939 and that is the figure. In that case it represents one well. I don't recall the figures as appearing in the record at all.

Q. You gave me a figure of 123 billion that you deducted for five wells in order to arrive at the figure at the first of the year that you are talking about, which would make it, if my calculation is correct, 24 billion instead of 23 billion. It is relatively unimportant—

A. This is 23,817,000,000. It is almost 24 billion, Mr. Spencer.

Q. All right.

A. Unless you figured it out exactly, that perhaps accounts for the difference. There is almost 24 billion.

Q. Five divided into 123 must go at least 24 times. Isn't that correct?

A. I see what you mean. That figure there is the expectancy and the start of its life with respect to five wells only and includes the 5 times 23815 plus whatever it produced.

We were up to the point of subtracting the expectancy and production of the five wells. That gets us back to the expectancy as of 12-31-38 of the wells producing at that date, which is not excluded in the five wells brought in in 1939 both as to their expectancy and their own production.

This reversed procedure can be continued back to the end or to the beginning of the early years, earlier years such as 1928. It would have been easier to have considered this from 1928, Mr. Spencer, in spite of the fact that the original

start was in 1939. However, you can work it from either direction. I think it makes a more comprehensive picture to start in 1928.

Q. Can it be done briefly the other way?

A. Yes, sir.

Q. All right, reverse it and put it in the other way, if the Examiner has no objection.

The Trial Examiner: No. However, I don't seem to follow him on this procedure he is going through now. It is probably clear if one would read it in the record. If it can be made plainer, Mr. Stevens, by reversing it, do so.

The Witness: I think it can. I think it can be better understood by most people a little better by starting in 1928, although I do start with a 1939 figure, to calculate back from there. You can start at the front and you can start at the back.

The Trial Examiner: Perhaps we might give you a few minutes to thrash it over.

We will stand in recess for five minutes.

(At this point a short recess was taken, after which proceedings were resumed as follows:)

The Trial Examiner: The hearing will be in order.

By Mr. Spencer:

Q. Now, Mr. Stevens, suppose we adopt your suggestion and put into the record an explanation of the method you utilized in figuring gas reserves as shown in Column 2, Page 5 of Mr. Luttring's Exhibit 190 by reversing the process.

A. The method of calculation of future expectancy for December 31st of any given year—the year 1929 is used in the example. The figures are in Mcf. on a 16.65 base. The term "expectancy" or "future expectancy" is synonymous with gas reserves recoverable by present wells for the years in question and is used for reasons of brevity and simplicity.

First, the expectancy of all wells as of 12-31-39 is 2,239,-849,016 Mcf., or 23.817543 billion for the average of 94 wells. That is as of the date of 12-31-39. This figure was derived from projection of pressure versus accumulative production

curve to intersect with an assumed 25-pound abandonment pressure and represents the gas reserves recoverable by Canadian River Gas Company as of 12-31-39.

The expectancy of the nine wells having first production in 1929 was obtained by multiplying the average well expectancy of 23.817543 Mcf. by 9, obtaining 214,357,887,000 Mcf. as of 12-31-39. To the expectancy as of 12-31-39 and to this expectancy of 4-12-39 is added the entire life of the production of the nine wells from the beginning of 1929. If it were shown by example from 1928 it would be the 35 wells as of 1928 but we are talking about 1929 in which nine wells were added. This amount is 30,876,429 Mcf.

The addition referred to gives 245,234,316 Mcf.

Q. In what year?

A. What this does is it has the effect of bringing the total expectancy of the nine wells back to the start of their lives which is at the beginning of 1929. It gets them to the instant which they were drilled in or assumed to be drilled in at the start of that year.

As the beginning of 1929 is considered the end of 1928, the expectancy at the first of 1929 of wells drilled in that area is added to the expectancy of other wells in existence at the first of 1929; that is, to the expectancy of other wells at the end of 1928.

Thus 245,234,316 Mcf. plus 1,029,892,131 Mcf. equals 1,275,126,447,000 Mcf. This figure includes production for the year in question and can be considered as the expectancy at the start of the year. The production that is included consists of production naturally for the nine wells drilled in 1929 as the entire life production was added previously, and the years production for the 35 wells already producing in 1928.

Therefore, to arrive at the expectancy for 12-31-29 it is necessary to subtract the production for 1929 of the 44 wells then involved. The production of 19,100,446 Mcf. is subtracted, giving 1,256,025,999 Mcf. This is the expectancy of the 44 wells producing at 12-31-39. The basic principle of the method used is started from 1928 to give yearly addition of wells, their proper contribution to expectancy. This expectancy is, of course, reduced by production.

The basic plan further considers addition of bands of wells for sucessive years and if this problem is considered as addition of successive bands of years and the expectancy of wells drilled in in those years followed by subtraction of the production of all wells operating at the end of those years, such operations arriving at an expectancy for the wells in existence at the end of those years.

Mr. Spencer: Is that clear to the Examiner?

The Trial Examiner: I think I can follow it in the record, as I have before.

By Mr. Spencer:

Q. Now, Mr. Stevens, you started out with 35 wells in 1928 and ended up with 94 wells in 1939, isn't that correct?
A. Yes, sir.

Q. In order that we may make our calculations, I wish you would from your working papers give the number of wells involved by years as you have used them.

A. 1928, 35; 1929, 44; 1930, 57; 1931, 65; 1932, 66; 1933, 71; 1934, 71, there being no additions in 1934; 1935, 74; 1936, 82; 1937, 86; 1938, 89; 1939, 94.

Q. Your list of wells contains wells that the company acquired by purchase rather than drilled, I assume you treated them no differently than you did those that were drilled by the company?

A. Well, these numbers of wells are the numbers of wells producing as of the end of those years when owned by Canadian River and when they are owned by Canadian River, of course, their expectancy is owned by the Canadian River. I believe that answers your question.

Q. Well, I think it does. You have made no distinction in your formula or method you have described here as between wells drilled by the company and wells acquired by the company but drilled by third parties?

A. Not when they were under Canadian River ownership. Then they were Canadian River wells, and no differential was made between those owned by Canadian River and their expectancy was owned by Canadian River.

Q. You didn't take into consideration production which might have come from those wells during their prior ownership, is that correct?

A. During their prior ownership their production didn't show up in your production and hence they are excluded for that reason.

Mr. Spencer: May I talk to the witness off the record a bit? There is no use of involving the record here.

The Trial Examiner: Yes. Off the record.

(Discussion outside the record.)

The Trial Examiner: On the record.

By Mr. Spencer:

Q. Now, Mr. Stevens, I take it from your testimony that you are an engineer by profession, is that right?

A. Yes.

Q. Have you ever made any particular studies or had any particular experience in determining proper rates of depreciation or depreciation for properties of oil and gas companies.

A. No.

Q. And is the same answer applicable to depletion?

A. Yes.

Q. Am I correct in stating that you are not recommending the treatment given to the data furnished by you in Mr. Luttring's Exhibit 190?

A. Well, that is a bit difficult to answer. Under your term "recommending," I believe that is a logical way to do but from an engineering point of view I suppose that the equipment in a gas well is used as long as the gas is there that is going to be recovered from those wells. Beyond that point of thinking that it is a logical thing to do, my recommendation probably has no value as such for the reason that beyond that point accounting features enter in upon which I don't feel competent to testify. It is simply a logical method and that is the extent of the recommended value that the tabulation may have.

Q. What Mr. Luttring has done, you did not recommend him to do?

A. I don't recall recommending that he make that specific report. The recommendations as far as they are recommendations were a statement of principle that we had some confidence in as being equitable in terms of a physical gas

property. That is really the sum and substance of the degree of recommendation.

Q. After all, a matter of depreciation and depletion is largely a question of amortizing your investment and getting it back at the proper time, is that correct?

A. That is my understanding.

Q. What part would you think that business judgment of the management might play in determining those questions?

A. I gave no consideration to that. I don't know whose business management or judgment is involved in that. The point of view given in these figures is irrespective of anything but what you might call physiologic. It incorporates no point of view of the management or accountants.

Q. I think that is right. You admit, however, that the question is not an academic one?

A. Not in its application.

Q. Who determined, if you know, that the reserve figures you furnished here should be applied to intangible wells cost?

A. I don't know specifically.

Q. Do you know why it was not applied to leaseholds, for instance.

A. This figure for reserves?

Q. Yes, in determining the rates for that.

A. The general reason is that it is clear it is not the lease reserve because some other figure is incorporated in Mr. Hammer's reserve as the figure for lease reserve.

Q. But still if this is all you are going to get out of present wells you would be wanting to get it out and get your money back on your leaseholds?

A. That isn't considered to be the fact, this being the reserve under wells, and the lease reserve being the total under leases to be recovered.

Q. You still have to get your money back through whatever wells you have, isn't that right?

A. Yes.

Q. Let me ask you this: You have made your calculation of reserves here as of 1939?

A. Yes, sir.

Q. Had you made that calculation for any of the pre-

ceding years down to 1928, the rate that Mr. Luttring arrived at would be changed, would it not?

A. Had we made it to some early date?

Q. Any date prior to this. You would have come out with a different rate, wouldn't you?

A. Whatever the reserve showed would have influenced the rate, I suppose. You are referring to Column 5 there. I suppose it would have its effect, however, they were made as of 1939, which is the present estimate.

Q. If we make it any date in the future, undoubtedly there would be some change in the rate, is that not right?

A. I am not thoroughly familiar with Mr. Luttring's procedure there and I would hesitate to answer affirmatively on that.

Q. Confine it to your reserves for the purpose of determining rate.

A. That is what he used—do I misunderstand you—

Q. I will shortcut.

You can use your method here in making your calculation for any year in the past and undoubtedly for any year in the future and find different reserves upon which to base your depletion computation, is that not correct?

A. This reserve is for present wells, of course, and those calculations are, I suppose, on present wells since they are on this figure.

Q. That is right.

A. As to what he would do in the calculation or in the application of any future reserve changed from our curve or staying on our curve, I don't know what he would do in that case, Mr. Spencer.

Q. He has stayed with your figure, hasn't he? He hasn't made any adjustment in your figures except the ones that you mentioned.

A. No, but they are as of 1939 and we are talking about the future, I believe.

Q. Yes, that is right. I won't go any further with that.

You say you have made no particular study of the depreciation and depletion and what a corporation should do with that?

A. No, sir.

Mr. Spencer: That is all.

The Trial Examiner: Do you have some redirect, Mr. March?

Mr. March: Yes.

Redirect Examination.

By Mr. March:

Q. Mr. Stevens, which one of these methods do you prefer for depleting the wells over the life of the wells or the life of the leases?

Mr. Spencer: Mr. Examiner, let us have him qualify the witness first. When I left him he wasn't qualified.

Mr. March: I asked him which one he preferred and that is all that is necessary for him to answer, if he has an opinion.

The Trial Examiner: I believe he just stated in response to cross examination, Mr. March, that he had made no study of the property depreciation and depletion other than that this system he proposes would be the logical method to use.

Mr. March: I want to know why he thinks it is the logical method.

The Trial Examiner: Is that what you want to know?

Mr. March: Yes.

The Trial Examiner: All right.

By Mr. March:

Q. Which one of the methods do you prefer and why?

A. Personally, I prefer this one described here as far as preference has any significance. Of course, it seemed that it was the logical one because it was tied in intimately with the life of the well or the use of the well—is tied in logically with the period of use and that is really the fundamental and probably the only basis of preference that the depletion is tied in with, the amount of gas that is going to be depleted. That seemed the very logical thing to me and that is probably the only and main reason for the preference.

Q. Your position is that you are depleting wells and that you should have the depletion period over the life of the wells?

A. Which is the history of the recoverable reserves, which is the period of producing from the recoverable reserves of the period in question. That is stating the same thing I believe.

Exhibit 190 is, in part, as follows:

5017

Exhibit No. 190

Schedule No. 1
Sheet 1 of 2

CANADIAN RIVER GAS COMPANY
CONDENSED INCOME AND EARNED SURPLUS ACCOUNT AS ADJUSTED
FOR THE YEAR ENDED DECEMBER 31, 1939
GIVING EFFECT TO ALTERNATIVE DEPLETION AS PROPOSED BY SUPPLEMENTAL ENTRY

Description (1)	As Adjusted (Note 1) (2)	Examiner's Supplementary Revision (Note 2) (3)	As Alternatively Adjusted (Note 3) (4)
Utility Income			
Operating Revenues	$2,393,386.99		$2,393,386.99
Operating Revenue Deductions			
Operating expenses	$ 665,286.93		$ 665,286.93
Depreciation	153,987.13		153,987.13
Depletion	44,865.27	$ 13,286.48	58,151.75
Taxes	175,141.03		175,141.03
Nonrecurring expenses	222.60		222.60
Total Operating Revenue Deductions	$1,039,502.96	$ 13,286.48	$1,052,789.44
Net Operating Revenues	$1,353,884.03	($ 13,286.48)	$1,340,597.55
Exploration and Development Costs			
Delay rentals	[illegible] 10,401.58		$ 10,401.58
Nonproductive well drilling	29,293.73		29,293.73
Abandoned leases	1,878.18		1,878.18
Total Exploration and Development Costs	$ 41,573.49		$ 41,573.49
Net Utility Income	$1,312,310.54	($ 13,286.48)	$1,299,024.06
Other Income			
Interest revenues	$ 17.88		$ 17.88
Miscellaneous nonoperating revenues	292.39		292.39
Total Other Income	$ 310.27		$ 310.27
Gross Income	$1,312,620.81	($ 13,286.48)	$1,299,334.33
Income Deductions			
Interest on debt to Colorado Interstate Gas Company			
Bonds	$ 327,235.00		$ 327,235.00
Notes and current account	104,962.71		104,962.71
Other interest charges	11,403.39		11,403.39
Miscellaneous income deductions	29,372.17		29,372.17
Total Income Deductions	$ 472,973.27		$ 472,973.27
Net Income for Year Ended December 31, 1939	$ 839,647.54	($ 13,286.48)	$ 826,361.06
Earned Surplus			
Credits			
Balance January 1, 1939	$4,998,551.16	($138,668.22)	$4,859,882.94
Balance from income account (above)	839,647.54	(1 ,286.48)	826,361.06
Total credits	$5,838,198.70	($151,954.70)	$5,686,244.00
Debit - Premium on bonds retired	11,900.00		11,900.00
Balance December 31, 1939	$5,826,298.70	($151,954.70)	$5,674,344.00

1

Exhibit No. 190

Docket G-124

Schedule No. 1
Sheet 2 of 2

CANADIAN RIVER GAS COMPANY
CONDENSED INCOME AND EARNED SURPLUS ACCOUNT AS ADJUSTED
FOR THE YEAR ENDED DECEMBER 31, 1939
GIVING EFFECT TO ALTERNATIVE DEPLETION AS PROPOSED BY SUPPLEMENTAL ENTRY

Notes:

(General) This supplementary statement of Respondent's income and earned surplus account for the year ended December 31, 1939, embraces the income and earned surplus account as adjusted and presented in the accounting report "Income Accounts and Supplemental Data Including Examiner's Reclassifications and Adjustments", and after giving effect to an alternative computation of annual depletion of gas well intangible costs, differing from the computation of annual depletion as made for the income and surplus account as first adjusted.

(1) The figures in this column are taken from column 9 of Statement B 1 of the report entitled "Income Accounts and Supplemental Data Including Examiner's Reclassifications and Adjustments and represent the Condensed Income and Earned Surplus Account for 1939 as adjusted.

(2) Basis of revision of annual depletion of gas well intangible costs for the year 1939 is as follows:

Depletion, per entry on Schedule No. 3 hereof	$39,625.53
Depletion, per entry 406 of report entitled "Annual and Accrued Depletion and Depreciation of Gas Plant Accounts and Examiner's Adjustments"	26,339.05
Additional depletion for the year 1939 on alternative basis	$13,286.48

(3) Although the Examiner's Suspensions for the Consideration of the Commission shown in Statement B 1 of the report entitled "Income Accounts and Supplemental Data Including Examiner's Reclassifications and Adjustments" are as pertinent to this schedule as they are to that statement, they have not been here repeated.

5021

Exhibit No. 190

CANADIAN RIVER GAS COMPANY
BALANCE SHEET AS ADJUSTED, DECEMBER 31, 1939
GIVING EFFECT TO ALTERNATIVE DEPLETION
AS PROPOSED BY SUPPLEMENTAL ENTRY

Assets and Other Debits (1)	As Adjusted (Note 1) (2)
Utility Plant:	
Gas plant in service	$ 9,923,329.94
Construction work in progress	150,582.36
Gas plant held for future use	80,952.45
Gas plant adjustments	4,091,880.88
Total Utility Plant	$14,246,745.63
Investment and Fund Accounts -	
Other physical property	$ 1,176.34
Current and Accrued Assets:	
Cash	$ 9,517.29
Special deposits	266.82
Working funds	1,492.36
Notes receivable (all from employees)	365.00
Accounts receivable from others, excluding associated companies	5,617.31
Receivables from associated companies	43,917.86
Materials and supplies:	
Held for use in gas business	67,452.29
Gasoline held for sale	3,484.62
Prepayments	4,445.40
Total Current and Accrued Assets	$ 136,558.95
Deferred Debits:	
Rate case expenses	$ 54,600.61
Other	34,519.70
Total Deferred Debits	$ 89,120.31
Total Assets and Other Debits	$14,493,601.23

Liabilities and Other Credits (3)	As Adjusted (Note 1) (4)	Examiner's Supplementary Revision (Note 2) (5)	As Alternatively Adjusted (6)
Capital Stock - Common capital stock 25,000 shares, no par value (all issued to Southwestern Development Company)	$ 1.00		$ 1.00
Long-Term Debt (All owed to Colorado Interstate Gas Company):			
First Mortgage and Collateral Trust Twenty Year Six Per Cent Sinking Fund Gold Bonds, due June 1, 1948	$ 5,057,000.00		$ 5,057,000.00
Advances	1,348,254.14		1,348,254.14
Total Long-Term Debt	$ 6,405,254.14		$ 6,405,254.14
Current and Accrued Liabilities:			
Accounts payable to other than associated companies	$ 134,256.95		$ 134,256.95
Payables to associated companies	272,037.81		272,037.81
Taxes accrued	81,291.82		81,291.82
Other current and accrued liabilities	11,097.53		11,097.53
Total Current and Accrued Liabilities	$ 498,684.11		$ 498,684.11
Reserves:			
Reserve for depreciation of gas plant	$ 1,437,396.70		$ 1,437,396.70
Reserve for amortization and depletion of producing natural gas land and land rights (See Schedule No. 4)	325,966.58	$ 151,954.70	477,921.28
Total Reserves	$ 1,763,363.28	$ 151,954.70	$ 1,915,317.98
Earned Surplus	$ 5,826,298.70	$(151,954.70)	$ 5,674,344.00
Total Liabilities and Other Credits	$14,493,601.23		$14,493,601.23

Notes:

(General) This supplementary statement of Respondent's balance sheet at December 31, 1939, embraces the balance sheet as adjusted and presented in the report entitled "Balance Sheet and Supplemental Data" and after giving effect to an alternative computation of annual and accrued requirement for depletion of gas well intangible costs, differing from the computation of such requirement in the balance sheet as first adjusted by the amount shown in column 5.

(1) The figures in this column are taken from column 5 of Statement A 1 of the report entitled "Balance Sheet and Supplemental Data" and represent the Balance Sheet as at December 31, 1939, as originally adjusted.

(2) See Schedule No. 3 for Examiner's entry supporting revision.

Exhibit No. 190

Docket G-124

Schedule No. 3
Sheet 1 of 2

CANADIAN RIVER GAS COMPANY
EXAMINER'S SUPPLEMENTAL ENTRY TO GIVE EFFECT TO
ALTERNATIVE METHOD OF ACCRUING DEPLETION OF GAS WELL
INTANGIBLE COSTS AS PROPOSED BY DIVISION OF GAS ENGINEERING

Particulars (1)	Debit (2)	Credit (3)
Surplus - Operating Revenue Deductions - Depletion	$151,954.70	
Reserve for Depletion of Gas Well Intangible Costs		$151,954.70

To provide annual depletion of gas well intangible costs based on undepleted gas reserves under the existing producing wells as estimated by the Bureau of Engineering, undepleted cost and annual production in amounts for the years as follows:

Year	Annual Depletion	Retirements	Reserve Acquired	Depletion Reserve
As of 12/31/27			$10,168.48	$ 10,168.48
1928	$ 8,286.50	$ 6,487.11		11,967.87
1929	19,138.65			31,106.52
1930	22,236.47			53,342.99
1931	20,632.47			73,975.46
1932	22,356.95			96,332.41
1933	20,802.91			117,135.32
1934	27,980.60			145,115.92
1935	30,404.00	14,345.87		161,174.05
1936	37,182.27			198,356.32
1937	40,084.82			238,441.14
1938	36,153.09			274,594.23
1939	39,625.53			314,219.76
	$324,884.26*	$20,832.98*	$10,168.48*	$314,219.76*
Previously set up by Examiner's Entry No. 406	172,929.56	20,832.98	10,168.48	162,265.06
Additional depletion	$151,954.70			$151,954.70

* Refer also to column 4 of Schedule No. 4, this report.

See data attached as per sheet 2 for undepleted reserves, annual production and annual depletion.

Exhibit No. 190

Docket G-124

Schedule No. 3
Sheet 2 of 2

CANADIAN RIVER GAS COMPANY
EXAMINER'S SUPPLEMENTAL ENTRY TO GIVE EFFECT TO
ALTERNATIVE METHOD OF ACCRUING DEPLETION OF GAS WELL
INTANGIBLE COSTS AS PROPOSED BY DIVISION OF GAS ENGINEERING

Year (1)	Gas Reserves (MCF) (2)	Annual Production (MCF) (3)	Annual Depletion Gas Well Intangible Costs (4)	Rate per MCF (5)
1928 (7 months)	1,036,427,228	6,535,097	$ 8,286.50	$ .001268
1929	1,275,126,447	19,100,448	19,138.65	.001002
1930	1,596,070,291	20,646,678	22,236.47	.001077
1931	1,777,717,880	20,819,847	20,632.47	.000991
1932	1,781,467,070	22,883,266	22,356.95	.000977
1933	1,894,232,604	21,990,394	20,802.91	.000946
1934	1,872,242,210	29,577,801	27,980.60	.000946
1935	1,937,068,722	34,628,703	30,404.00	.000878
1936	2,110,160,888	43,590,010	37,182.27	.000853
1937	2,177,058,509	46,610,252	40,084.82	.000860
1938	2,204,636,366	42,483,068	36,153.09	.000851
1939	2,285,632,410	46,783,394	39,625.53	.000847
1940	2,238,849,016			
Totals	x x x x	355,648,958	$324,884.26	$ .000913

All MCF data above are stated on a pressure base of 14.65 pounds per square inch absolute.

Gas reserves shown in column 2 represent remaining gas reserves under the existing wells as of the beginning of each accounting period. All amounts in column 2 were derived by adding the annual production to the remaining gas reserves under the producing existing wells at the end of each accounting period.

Exhibit No. 190 6

OF GAS PLANT IN SERVICE AT DECEMBER 31, 1939
AFTER GIVING EFFECT TO ALTERNATIVE DEPLETION
AS PROPOSED BY DIVISION OF GAS ENGINEERING

Particulars (1)	Total (2)	Total Depletable Plant (3)	Depletable Plant: Gas Well Intangible Costs (4)	Depletable Plant: Leasehold Costs (5)	Total Depreciable Plant (6)	Non-Depreciable Plant (7)
Costs Subject to Depletion and Depreciation						
Original Charges Per Books	$15,536,159.96	$8,064,115.85	$2,175,[illegible]90.13	$5,888,125.72	$7,467,175.44	$4,868.67
Adjustments	(4,596,458.77)	(3,966,934.14)	286,547.99	(4,253,482.13)	(628,348.29)	(1,176.34)
Adjusted Total Cost Subject to Depletion and Depreciation	$10,939,701.19	$4,097,181.71	$2,462,538.12	$1,634,643.59	$6,838,827.15	$3,692.33
Less Retirements (adjusted)	1,016,371.25	283,657.37	253,034.39	30,622.98	732,713.88	
Adjusted Book Cost at Dec. 31, 1939	$ 9,923,329.94	$3,813,524.34	$2,209,503.73	$1,604,020.61	$6,106,113.27	$3,692.33
Depletion and Depreciation, computed annually; depletion computed on remaining gas reserves estimated by Bureau of Engineering and annual production of Canadian River Gas Co., depreciation based on service life estimates furnished by Bureau of Engineering:						
Year						
1928	$ 74,460.73	$ 9,181.80	$ 8,286.50	$ 895.30	$ 65,278.93	
1929	161,351.88	22,003.72	19,138.65	2,865.07	139,348.16	
1930	167,355.15	27,996.89	22,236.47	5,760.42	139,358.26	
1931	171,735.36	26,857.60	20,632.47	6,225.13	144,877.76	
1932	176,151.06	29,221.93	22,356.95	6,864.98	146,929.13	
1933	175,626.00	27,729.88	20,802.91	6,926.97	147,896.12	
1934	187,458.64	37,327.19	27,980.60	9,346.59	150,131.45	
1935	189,179.61	41,312.04	30,404.00	10,908.04	147,867.57	
1936	196,545.31	50,913.12	37,182.27	13,730.85	145,632.19	
1937	199,490.50	54,767.05	40,084.82	14,682.23	144,723.45	
1938	202,670.94	49,662.71	36,153.09	13,509.62	153,008.23	
1939	212,138.88	58,151.75	39,625.53	18,526.22	153,987.13	
Total Annual Accruals	$ 2,114,164.06	$ 435,125.68	$ 324,884.26	$ 110,241.42	$1,679,038.38	
Less Retirement Losses						
Retirements (adjusted)	$ 1,016,371.25	$ 283,657.37	$ 253,034.39	$ 30,622.98	$ 732,713.88	
Salvage	(633,022.23)	(259,523.00)	(232,201.41)	(27,321.59)	(373,499.23)	
Profit on retirements transferred to maintenance	3,664.08				3,664.08	
Loss on retirements charged to reserve	$ 387,013.10	$ 24,134.37	$ 20,832.98	$ 3,301.39	$ 362,878.73	
Net (annual accruals less retirement losses)	$ 1,727,150.06	$ 410,991.31	$ 304,051.28	$ 106,940.03	$1,316,159.65	
Add						
Reserves acquired	180,135.42	66,929.97	10,139.54	56,790.43	113,205.45	
Accrual charged to construction	8,031.60				8,031.60	
Total Reserves for Depletion and Depreciation applicable to Gas Plant	$ 1,915,317.98	$ 477,921.28	$ 314,190.82	$ 163,730.46	$1,437,396.70	
Deduct - Reserves applicable to Gas Plant Held for Future Use	3,763.12	1,423.16	(28.94)	1,452.10	2,339.96	
Total Reserves for Depletion and Depreciation applicable to Gas Plant in Service at December 31, 1939, as adjusted	$ 1,911,554.86	$ 476,498.12	$ 314,219.76	$ 162,278.36	$1,435,056.74	

Exhibit No. 190 7

Docket G-124

Schedule No. 4
Sheet 2 of 2

CANADIAN RIVER GAS COMPANY
SUMMARY OF ANNUAL AND ACCRUED DEPLETION AND DEPRECIATION
OF GAS PLANT IN SERVICE AT DECEMBER 31, 1939
AFTER GIVING EFFECT TO ALTERNATIVE DEPLETION
AS PROPOSED BY DIVISION OF GAS ENGINEERING

Particulars	Total	Total Depletable Plant	Depletable Plant: Gas Well Intangible Costs	Depletable Plant: Leasehold Costs	Total Depreciable Plant	Non-Depreciable Plant
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Net Adjusted Book Cost at Dec. 31, 1939						
Adjusted Original Book Cost	$ 9,923,329.94	$3,813,524.34	$2,209,503.73	$1,604,020.61	$6,106,113.27	$3,692.33
Adjusted Depletion and Depreciation Reserves Applicable to Gas Plant in Service	1,911,554.86	476,498.12	314,219.76	162,278.36	1,435,046.74	
Net Book Cost - Gas Plant in Service	$ 8,011,775.08	$3,337,026.22	$1,895,283.97	$1,441,742.25	$4,671,056.53	$3,692.33

The testimony with respect to salvage is also abstracted under Title 27 supra as to Colorado Interstate's salvage. As shown in Exhibit 281, WITNESSES TAUBMAN, SMITH and SOLOW, the salvage value as of January 1, 1956, of Canadian's property is stated to be $198,384.69.

61. **Rate of Return.**

Under title 28 supra the evidence on rate of return submitted by WITNESSES COFFMAN, Exhibit 73, GILMAN, Exhibit 74, SANDS, Exhibit 92, and BOSWORTH, Exhibit 93, for Canadian and Colorado Interstate, and KNAPP, Exhibits 225 and 225-A, for the Commission, is abstracted.

62. **Company's Statement as to Revenue Required to be Received by Canadian on a Regulatory Rate Basis for all Gas Delivered Colorado Interstate at Clayton Junction in Order to Produce a Fair Return on the Fair Value of Canadian's Property.**

This is shown in Exhibit 276 (Vol. LXXXIV, pp. 14439, et seq.). Witness Lusk.

The costs of operations of Canadian from 1939 to 1947, inclusive, are computed on a regulatory rate basis without regard to the contract between Canadian and Colorado Interstate (Exhibit 16). Such costs of operation are related to the original cost of the property owned by the company, as set forth in Exhibits 183 and 184 for production and gathering facilities, and Exhibits 67 and 133 as to Canadian's portion of the Denver Line. The costs are divided between the well mouth production system, the gathering system and the transmission system, and there is shown the portion of such costs which constitute the cost to Colorado Interstate of all gas delivered to it at Clayton Junction, New Mexico.

Lusk testified the revenue thus required, in his opinion, would provide: (a) costs arising from operating and maintaining the property, including income and all other taxes; (b) proper allowance for depletion and depreciation; and (c) a reasonable return on the fair value of the property.

Most of the costs arising from the operation and mainte-

nance of the property are directly charged to the production system, the gathering system and the transmission system. The costs which are undistributed on the company's books he divided as between the three systems pro rata with the directly charged expenses relating to each.

The costs of operations in 1939 is shown in Exhibits 91 and 163 (previously abstracted) were reduced by the amounts of certain general construction costs related to property additions made in 1939, which are included as capital charges in Exhibits 67, 133, 183 and 184, also above abstracted.

The total costs of operations are summarized on Statement 6, and their division by major operating accounts and systems is shown on Statements 7, 8 and 9.

Statement 6 is shown below in three sections:

Calendar Year (1)	Gas Expenses (A) (2)	Taxes (G) (3)	Other Expenses (E) (4)	Total Expense (5)	Less Other Revenues (E) (6)
1939	$341,959	$114,597	$451,082	$ 907,638	$177,691
1940	419,752	118,900	493,763	1,032,415	140,261
1941	380,077	124,300	492,566	996,943	151,221
1942	333,402	132,400	538,300	1,004,102	154,551
1943	366,127	138,400	560,924	1,065,451	155,522
1944	374,952	144,900	590,455	1,110,307	158,713
1945	378,377	150,600	581,849	1,110,826	161,904
1946	381,002	149,100	528,209	1,058,311	161,904
1947	390,327	133,100	323,669	847,096	161,904

Notes: (A) As shown on Statement No. 7 attached.

(B) As shown on Statement No. 10 attached.

(C) As shown on Statement No. 11 attached.

(D) As shown on Statement No. 13 attached.

(E) As shown on Statement No. 18 attached.

(F) Corresponds to total shown on Statement No. 5 attached.

(G) As shown in Column 5, Statement No. 9 attached.

(H) Includes an allowance of 8 per cent return, and depletion, depreciation and amortization of property by a sinking fund method with interest at 2¾ per cent annually.

Net Operating Expense (7)	Replacement Reserve (B) (8)	Provision for Depreciation and Depletion (B) (9)	Amount Required for 8 Per Cent Return (C) (10)	Federal Taxes (D) (11)	Total (F) (12)
$729,947	$10,614	$570,664	$ 868,233	$ 74,705	$2,254,163
892,154	10,614	570,664	909,027	137,318	2,519,777
845,722	10,614	570,664	939,262	194,658	2,560,920
849,551	10,614	570,664	968,430	229,147	2,628,406
909,929	10,614	570,664	1,010,501	279,763	2,781,471
951,594	10,614	570,664	1,029,637	337,574	2,900,083
948,922	10,614	570,664	1,042,829	401,734	2,974,763
896,407	10,614	570,664	1,056,365	520,500	3,054,550
685,192	10,614	570,664	1,070,221	780,743	3,117,434

The rate base used as of January 1, 1939, is the original cost as of December 31, 1938, less the accumulated depreciation as of said date, shown in Exhibits 272 and 273, Witness Roberts, above abstracted, plus working capital as of that date, shown in Exhibit 192, also abstracted above under that heading.

For the years after 1939 there were added, to obtain the property rate base at January 1 of each year, subsequent additions actually made in 1939, as shown in Exhibits 67 and 183, and as estimated, for subsequent years through 1947 by Exhibits 133 and 184, all of which exhibits have been abstracted above. Such property rate base, separated as between production, gathering and transmission systems, including the gasoline plant, as of January 1 of each year, 1939 to 1948, inclusive, is shown on Statement 10 as follows:

1939	$10,662,903
1940	11,157,829
1941	11,520,772
1942	11,875,372
1943	12,386,265
1944	12,605,465
1945	12,760,365
1946	12,919,565
1947	13,102,765
1948	13,135,965

Allowance was made for depletion and depreciation by the sinking fund method, whereby the annual installments, accumulated by compound interest at 2¾%, will return such depreciated original cost of the property in use on January 1, 1939, and the additions through 1947, at the end of 1956. Such period of time was based upon Exhibit 255, elsewhere abstracted, in which the respondent's witness Hendee testified the economic life of the field would cease by the end of 1956.

The rate of 2¾% interest used in connection with the sinking fund was taken from the rates shown for ten public utility AAA bonds and U. S. Treasury Bonds, as shown on Schedules 3 and 4 in Exhibit 225, Commission Witness Knapp.

An allowance was also made for the annual accumulation of funds needed for the replacement of short-lived property, such as automobiles, trucks and drilling and cleaning equipment, separate and apart from the provision made in the sinking fund requirement for depletion and depreciation. An 8% return was adopted, using as a basis Exhibits 73, 74, 92 and 93, abstracted under Title 28, "Necessary Rate of Return," supra.

Federal income taxes, at presently existing rates and without considering the possibility of increased rates in the future, were computed on the estimated earnings of the company under such regulatory rate basis.

The total gas revenues to which Canadian states it is entitled on a regulatory rate basis are summarized on Statement 5 by operating systems for the years 1939 to 1947, inclusive, and are shown below:

Year (1)	Production (2)	Transmission (3)	Gathering (4)	Total (5)
1939	$1,417,743	$255,486	$580,934	$2,254,163
1940	1,550,558	267,621	701,598	2,519,777
1941	1,565,750	269,275	725,895	2,560,920
1942	1,612,886	289,256	726,264	2,628,406
1943	1,671,724	308,999	800,748	2,781,471
1944	1,743,001	325,285	831,797	2,900,083
1945	1,773,903	340,193	860,667	2,974,763
1946	1,805,776	355,701	893,073	3,054,550
1947	1,806,694	377,724	933,016	3,117,434

This is also shown on Statement 6 by principal operating accounts. The distribution of such costs and revenues are summarized by production, gathering and transmission systems on Statements 2, 3, and 4, supported by Statements 7 to 12, inclusive.

The agreement of January 3, 1928, between Canadian and Colorado Interstate (Exhibit 16) makes provision for the division of costs as between separate deliveries of gas which make joint use of certain facilities.

In this Exhibit 276 such methods provided in the contract are used in assigning the required revenues of the company to the deliveries of all gas at Clayton Junction. For example, the required revenues from transmission line operations are

assigned to Clayton Junction deliveries in the proportion that those deliveries bear to the total amount of gas delivered from Canadian's transmission line; the required revenues from gathering operations are assigned to Clayton Junction deliveries in the proportion that the gas gathered to make such deliveries (including a pro rata share of gas used at Bivins) bears to the total gas gathered; and the required revenues from well mouth operations are assigned to Clayton Junction deliveries in the proportion that the gas produced to make such deliveries (including the pro rata share of gas used in gathering) bears to the total well mouth production.

The percentages of production, gathering and transmission revenues chargeable to Colorado Interstate for all gas delivered at Clayton Junction as used in the exhibit are shown in the next to the last column on Statements 2, 3 and 4, and are identical with those used in the cost determination made for all gas under the basic contract terms in Exhibit 164, Statement 9, hereinabove abstracted. These percentages for the years 1939 to 1947, inclusive, shown on Statements 2, 3 and 4, for production, gathering and transmission, are as follows:

Production	Gathering	Transmission
45.36%	50.57%	97.70%
45.69	52.47	97.76
46.91	54.32	97.91
42.80	48.73	97.95
40.72	46.01	97.95
38.98	43.69	97.99
38.05	42.43	98.02
42.50	48.04	98.02
77.44	98.02	98.02

Applying these percentages to the total figures (all gas) in Statement 5 above, Statement 1 summarizes the amounts determined in the manner above described that Canadian states it is entitled to receive under a regulatory rate basis from Colorado Interstate for all gas delivered at Clayton Junction, as follows:

Year	Production	Gathering	Transmission	Total
1939	$ 643,088	$129,199	$567,573	$1,339,860
1940	708,450	140,421	685,882	1,534,753
1941	734,493	146,270	710,724	1,591,487
1942	690,315	140,954	711,376	1,542,645
1943	680,726	142,170	784,333	1,607,229
1944	679,422	142,117	815,078	1,636,617
1945	674,970	144,344	843,626	1,662,940
1946	767,455	170,879	875,390	1,813,724
1947	1,399,104	370,245	914,542	2,683,891

Additional testimony of Mr. Lusk in connection with this exhibit appears under title 32 supra.

63. Revenue Claimed to be Required by Canadian on a Regulatory Rate Basis for all Gas Delivered to Colorado Interstate at Clayton Junction, Except Colorado Interstate's Direct Sale Gas, in Order to Produce a Fair Return on a Fair Value of Canadian's Property.

Under the title preceding this one (Exhibit 276), the evidence is abstracted, showing Canadian's claimed required revenues under a regulatory rate basis from all gas delivered at Clayton Junction, New Mexico, to Colorado Interstate.

In this Exhibit 277 (Vol. LXXXXIV, pp. 14453, et seq.), Witness Lusk testified that if Colorado Interstate's direct sales were eliminated, the total annual costs would be lower, due to the reduced facilities and the reduced volumes of gas required.

Such lower costs were reflected in Exhibits 134 and 193, showing the equivalent original costs of Canadian's property for resale gas only; Exhibits 274 and 275, showing the accumulated depreciation as applied to such equivalent original cost, and Exhibit 165, showing the costs of operations, involving resale gas alone by Colorado Interstate. The costs of operation shown in the latter exhibit were further reduced in this Exhibit 277 by the amount of certain

general construction costs related to property additions in 1939, which were included as capital costs (Exhibits 134 and 193).

This Exhibit 277 shows the annual revenues required from all gas, except Colorado Interstate's direct sale gas, at Clayton Junction, New Mexico, determined in a manner identical with that for all gas delivered at Clayton Junction in Exhibit 276, abstracted in Title 34. The percentages of production, gathering and transmission chargeable to Colorado Interstate on Statements 2, 3 and 4 are identical with those used in the cost determination for resale gas in Exhibit 167, abstracted in Title 30.

(All of the exhibits above referred to have been abstracted above.)

Statement 1 of Exhibit 277 shows the claimed required revenues from all gas delivered to Colorado Interstate at Clayton Junction except its direct sale gas on a regulatory rate basis, for years 1939 to 1947, inclusive, as follows:

Required Revenues from Gas on a Regulatory Rate Basis (A) Resale Gas Delivered at Clayton Junction, New Mexico, to Colorado Interstate Gas Company, 1939 to 1947, Inclusive.

Year (1)	Production (B) (2)	Gathering (B) (3)	Transmission (B) (4)	Total (5)
1939	$ 399,115	$ 85,430	$566,534	$1,051,079
1940	461,301	99,940	693,264	1,254,505
1941	485,734	105,900	709,237	1,300,871
1942	454,798	100,578	714,040	1,269,416
1943	453,881	101,618	771,254	1,326,753
1944	456,048	102,175	826,520	1,384,743
1945	457,472	104,682	854,009	1,416,163
1946	536,437	128,653	880,991	1,546,081
1947	1,201,815	378,896	909,202	2,489,913

Notes: (A) Includes an allowance of 8 per cent return and depletion, depreciation and amortization of property by a sinking fund method with interest at 2¾ per cent annually.

(B) Amounts in Columns (2), (3) and (4) from Statements Nos. 2, 3 and 4 respectively.

Additional testimony of MR. LUSK in connection with this exhibit appears under title 32 supra.

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64. Canadian's Statement of Operating Costs Under Basic Contract Terms for all Gas Delivered to Colorado Interstate at Clayton Junction Apportioned Between Resale Gas and Direct Sale Gas.

Under title 35 supra, Exhibit 316, Witness Rhodes (Vol. CII, p. 15881), is abstracted. That exhibit is entitled "Methods of Apportioning Costs of the Producing and Gathering Facilities of Canadian River Gas Company and of the Denver Line Between Resale Gas and Direct Sale Gas 1928 to 1947, Inclusive." Colorado Interstate's brief, however, dealt mainly with the Denver Line.

MR. RHODES further testified in connection with Exhibit 316 as follows:

3. Apportionment of Gas Leaseholds.

Gas leaseholds are owned for the purpose of supplying the current and future market requirements of gas. The markets served and delivery points named in the order of their priority or preference, as provided by existing contracts, are:

1. To Amarillo Oil Company for its markets in Amarillo and its environs and to domestic consumers in North Texas as described in the third paragraph of the Canadian River-Colorado Interstate agreement of January 3, 1928, which is Exhibit No. 16 in this proceeding. Deliveries are presently made from the well mouth for certain of these markets and from the Denver line for Hartley, Dalhart and Texline, Texas.

2-A. To Colorado Interstate Gas Company for its customers in and near Denver, Pueblo and Colorado Springs, Colorado and others served from the Denver line as described in Paragraph Fifteenth of Colorado Interstate's agreement with Natural Gas Pipeline Company of America dated October 15, 1931 which is Exhibit No. 7-G in this proceeding. Deliveries are made to Colorado Interstate from the Denver line at Clayton Junction, New Mexico.

2-B. To Clayton Gas Company which company was originally a customer of Colorado Interstate Gas Company. Deliveries are made from the Denver line near Clayton, New Mexico.

3. To Colorado Interstate Gas Company for delivery to Natural Gas Pipeline Company of America. Deliveries are made by Canadian River Gas Company at Gray's Junction, Oklahoma. Deliveries at this point are made possible by lease and operating agreements between Canadian River Gas Company and Texoma Natural Gas Company relative to the use of transportation facilities from the Fritch compressor station of Texoma Natural Gas Company in Texas to the delivery point at Gray's Junction, Oklahoma.

The contract of October 15, 1931 with Natural Gas Pipeline Company further requires that Colorado Interstate refrain from making hereafter and consenting that Canadian River Gas Company may make hereafter any sales exclusive of those indicated above, of any gas from the gas properties of Canadian River Gas Company in quantities in excess of 18,250,000 Mcf. per year.

Notwithstanding the Denver line's priority rights in the gas supply of Canadian River over those of the Chicago line, Canadian River's acreage has been apportioned with the aggregate volumes of gas heretofore marketed and anticipated to be marketed within a reasonable period in the future. Chicago gas might appropriately have been charged for the use of leaseholds on an incremental basis whereby the base or foundation costs would have to be borne by and divided between the Denver line gas and Amarillo gas on some equitable basis.

This ratio is designated as the project volume ratio which as applied to any class of business is the ratio of the volume of gas required for that business during the period under consideration to the total volume of all classes of business during the same period. For the purpose of this study there have been taken the actual and estimated volumes produced from the begining of regular operation of the Denver line through 1947. The volumes of gas sold or required in future operations for each delivery point and class of business used in the development of the project ratios

shown on Statement No. 1, have been taken from Exhibits Nos. 78 and 80. In determining this ratio all requirements must be converted into the net amounts of gas required to be produced on account of the facts that (a) deliveries to the Denver line are made at the Bivins Station discharge (i.e., less gas used at Bivins), (b) all other sales including deliveries for the Chicago line are at the Fritch Station suction and (c) deliveries to Amarillo Oil Company for certain markets are at the well mouth. These ratios taken from the column footings of Statement No. 1 are as follows:

Resale Gas From the Denver Line:	
Local deliveries to Amarillo Oil Company and Clayton Gas Company	1.05%
Colorado Interstate Gas Company	24.85
Total Resale	25.90%
Direct Sale Gas From the Denver Line:	
Colorado Interstate Gas Company	22.23
Total Denver Line	48.13%
All Other Sales	51.87
Total Net Well Mouth Requirements	100.00%

The operating costs related to leaseholds are royalties and delay rentals. The royalties are paid pro rata with the volumes produced each year. They are properly apportioned pro rata with the net amounts of gas required to be produced each year, also shown on Statement No. 1. The delay rentals are properly apportioned on the same basis as the leaseholds.

4. Apportionment of Other Well Mouth Production Costs

The number of wells required in the development of natural gas acreage is fixed both by the maximum demands for gas to be produced and by leasehold requirements. The maximum daily production of any one of Canadian River's wells is limited by State control to 25 per cent of the daily open flow of that well. The maximum production from any lease is fixed by internal proration among leases under which

the company operates. This internal proration is based on total monthly requirements. It thus appears that the number of wells required by Canadian River is controlled both by the maximum daily demand and by the maximum monthly demand.

Canadian River's total original cost of wells and annual expenses on account of the wells (except royalties and taxes based on the volume of production) is controlled largely by the number of wells required. These costs are not affected by the volume of gas produced in any year. These costs are thus controlled by the maximum daily production and by the maximum monthly production.

The maximum daily production of Canadian River's wells on account of Denver line resale gas and Denver line direct sale gas is determined not only by the requirements of these two classes of gas on that day but by the amount of gas delivered into the Denver line for storage through building up of line pressures which is in control of the operator. The ratio of maximum daily requirements to maximum monthly requirements of resale gas is higher than such ratio related to direct sale gas and to gas for the Chicago line. In this exhibit the maximum monthly requirements are used as a basis of apportionment thus charging to resale gas less than its full share of the Company's costs.

The apportionment of Canadian River's original cost of wells and of annual expenses of well mouth production (except royalties and taxes based on volume of production) are thus appropriately apportioned as between the several classes or gas pro rata with the respective maximum monthly volumes of gas produced to meet their requirements. The ratios to be determined for any year are based upon the maximum monthly requirements during the winter in which the year begins. The independent monthly maximum for each class of gas is used and expressed in terms of a 31 day month. These maximum monthly requirements are shown both in terms of gas sold and gas produced on Statement No. 5 together with the determination of the maximum month ratios for the several classes of gas involved for each year of the project period.

The apportionment of royalties and delay rentals is de-

scribed in Section 3 above. The remaining well mouth production costs are principally controlled by the annual volume of gas handled and in general comprise gas purchased and severance taxes assessed on the basis of annual volume of production. These remaining items of cost are appropriately apportioned as between the several classes of gas pro rata with the respective annual volumes of gas produced to meet their requirements. These annual volumes expressed both in terms of gas sold and of gas produced are shown on Statement No. 1, together with the determination of the annual volume ratios for the several classes of gas for each year of the project period.

5. Apportionment of Gathering Costs

The costs of gathering gas are wholly unaffected by the volume produced each year. They are controlled by peak loads like well equipment costs. These costs, both capital and operating, are appropriately apportioned on the basis of the maximum month ratios. These ratios for gathering system costs have been developed as shown on Statement No. 6.

* * * * * *

Other apportionments of pipe line capacities should not be used for the reasons outlined below:

(A) If the resale business and the direct sale business had equal primary rights to the net capacity of the line, instead of the resale gas having the first call and the direct sale gas having only what was left, then the direct sale gas would have 38.2 per cent of the net firm capacity of the line or 33,000 Mcf. per day as a primary business instead of 8,000 Mcf. per day as the secondary business, as shown above. With equal primary rights in the line then the resale gas and the direct sale gas might expect to share the costs pro rata with their quotas in the flow capacity of the line.

Since the resale gas and direct sale gas do not have equal rights in the line, equal sharing of the costs would result in a gross overcharge to the direct sale business and a gross undercharge to the resale business. The direct sale gas would have the right to 8,000 Mcf. per day of the net firm capacity of the line but would pay

for 33,000 Mcf. per day. It would get about 24 per cent of the net capacity it paid for. On the other hand, the resale gas would get 78,500 Mcf. per day of the net firm capacity of the line but would pay for only 53,500 Mcf. per day. It would get over 147 per cent of the net capacity it paid for. The direct sale gas would thus pay about six times (147/24) as much per unit of firm capacity as the resale gas. Sharing of costs between resale gas and direct sale gas pro rata with their respective peak load obligations (namely, 61.8 per cent and 38.2 per cent respectively) is seen to result in a gross overcharge to direct sale gas.

(B). The error would be further magnified if costs were shared pro rata with annual volumes of gas because the estimated 1940 sales were 52.87 per cent resale gas and 47.13 per cent direct sale gas. Such a basis of charge would result in the direct sale gas paying about eight and one half ($8\frac{1}{2}$) times as much for its line capacity as the resale gas.

* * * * *

Canadian River Gas Company — Statement No. 6

Maximum Month Ratios of Gas Gathered and Sold

By Delivery Points and Kinds of Denver Line Business, 1928 to 1947 Inclusive

Item No.	Winter of Years	Net Gas Gathered		Less Fritch Deliveries		Apportionment of Denver Line Business: Bivins Input		Total Resale		Clayton & A.O.C. Resale		Deliveries to Colorado Interstate: Resale		Direct Sale	
		Mcf. (A)	Per Cent	Mcf. (A)	Per Cent	Mcf. (A)	Per Cent	Mcf. (B)	Per Cent	Mcf. (B)	Per Cent	Mcf. (B)	Per Cent	Mcf. (B)	Per Cent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	1928-1929	985,461	100.00%	—	—	985,461	100.00%	434,096	44.05%	38,039	3.86%	396,057	40.19%	551,365	55.95%
2	1929-1930	1,544,106	100.00	—	—	1,544,106	100.00	798,303	51.70	48,022	3.11	750,281	48.59	745,803	48.30
3	1930-1931	1,665,685	100.00	130,443	7.83%	1,535,242	92.17	874,627	52.51	40,223	2.42	834,404	50.09	660,615	39.66
4	1931-1932	2,571,311	100.00	915,486	35.60	1,655,825	64.40	988,362	38.44	42,058	1.64	946,304	36.80	667,463	25.96
5	1932-1933	2,069,976	100.00	583,842	28.21	1,486,134	71.79	888,708	42.93	39,977	1.93	848,731	41.00	597,426	28.86
6	1933-1934	2,452,024	100.00	1,016,518	41.46	1,435,506	58.54	741,726	30.25	40,481	1.65	701,245	28.60	693,780	28.29
7	1934-1935	2,702,806	100.00	1,315,202	48.66	1,387,604	51.34	794,126	29.38	41,212	1.52	752,914	27.86	593,478	21.96
8	1935-1936	3,618,765	100.00	1,531,545	42.32	2,087,220	57.68	1,058,012	29.24	55,312	1.53	1,002,700	27.71	1,029,208	28.44
9	1936-1937	3,844,999	100.00	1,638,783	42.62	2,206,216	57.38	1,248,056	32.46	62,656	1.63	1,185,400	30.83	958,160	24.92
10	1937-1938	3,396,333	100.00	1,620,557	47.71	1,775,776	52.29	1,097,074	32.30	57,713	1.70	1,039,361	30.60	678,702	19.99
11	1938-1939	3,838,407	100.00	1,631,216	42.50	2,207,191	57.50	1,317,031	34.31	64,450	1.68	1,252,581	32.63	890,160	23.19
12	1939-1940	4,018,123	100.00	1,645,204	40.94	2,372,919	59.06	1,463,379	36.42	69,289	1.73	1,394,090	34.69	909,540	22.64
13	1940-1941	4,301,332	100.00	1,716,382	39.90	2,584,950	60.10	1,602,927	37.27	72,895	1.70	1,530,032	35.57	982,023	22.83
14	1941-1942	4,852,609	100.00	2,208,921	45.52	2,643,688	54.48	1,657,857	34.16	73,230	1.51	1,584,627	32.65	985,831	20.32
15	1942-1943	5,144,456	100.00	2,484,490	48.29	2,659,966	51.71	1,702,378	33.09	73,415	1.43	1,628,963	31.66	957,588	18.62
16	1943-1944	5,505,860	100.00	2,791,267	50.70	2,714,593	49.30	1,752,541	31.83	73,837	1.34	1,678,704	30.49	962,052	17.47
17	1944-1945	5,770,268	100.00	3,001,527	52.02	2,768,741	47.98	1,802,450	31.23	74,202	1.28	1,728,248	29.95	966,291	16.75
18	1945-1946	5,945,208	100.00	3,176,467	53.43	2,768,741	46.57	1,802,450	30.32	74,202	1.25	1,728,248	29.07	966,291	16.25
19	1946-1947	2,768,741	100.00	—	—	2,768,741	100.00	1,802,450	65.10	74,202	2.68	1,728,248	62.42	966,291	34.90
20	Total	66,996,470	100.00%	27,407,850	40.91%	39,588,620	59.09%	23,826,553	35.56%	1,115,415	1.66%	22,711,138	33.90%	15,762,067	23.53%

Notes: (A) Column Nos. 1, 3 and 5 from Statement No. 8 Column Nos. 8, 9 and 10 respectively.

(B) Column Nos. 7, 9, 11 and 13 obtained by multiplying Column No. 5 by percentages shown on Statement No. 7 Column Nos. 4, 6, 8 and 10 respectively.

Commission Witness Lester (whose qualifications are given at pp. 12877 to 12881), testified as follows: (Vol. CI, pp. 15641-15647.)

Q. On Page 4-B of the statement, if you will turn back to that page now, you have on Page 4-B and 4-A recited certain provisions of the contract between the Canadian River Gas Company and Colorado Interstate Gas Company, and then at the bottom of Page 4-B you make a statement that this subjection of the deliveries to the Interstate company to preference obligations of other contracts is most unusual.

Now, haven't you found in studies of contracts in other fields or other gas companies that frequently where contracts for the sale of gas have been in effect for some time and later contracts are made, that the later contracts are made subject to the obligations of the prior ones?

A. I wasn't referring to that particular thing. What I was referring to as the most unusual thing was that the lower priced gas was being given preference to a higher priced gas. That's actually what I had reference to.

Q. It, of course, was prior in point of time that the deliveries to Amarillo Oil Company were made?

A. That's correct.

Q. Yes. That's where the preference lies, was the fact that the Amarillo Oil Company had been getting gas from them before Colorado Interstate ever came into existence?

A. That's correct.

Q. Now, if you will turn to Exhibit 262 and to your written statement, Page 3, the two items at the top of the page referring to sales of Colorado-Wyoming Gas Company for transportation and resale and to Natural Gas Pipeline Company of America for transportation and resale, now in the use of the word "transportation," I take it you did not mean to imply that those companies were transporting gas for Colorado Interstate Gas Company?

A. No. They are transporting gas for themselves. They are called transportation companies and I was using the phrase merely to mean that the Colorado-Wyoming Gas Company received the gas from the Colorado Interstate Gas Company and transported it for resale.

Q. Yes, I see. Now, then, on Page 4 you have at the

bottom of the page and again on Page 5, certain figures. Do I understand that all of those prices per Mcf. are on the basis of the pressure base of 14.65 pounds?

A. Yes, I'm pretty sure. I'll look it up and see.

Q. The reason I asked you that, for example, you show average revenue for domestic gas 42.1 cents and that is higher than any of the schedules provide for, so I assume that your figures there must be on the uniform pressure base which the Commission uses rather than on the contract pressure base?

A. These are on the uniform pressure base.

Q. That's 14.65?

A. 14.65 pounds.

Q. And using that pressure base would cause a higher cents per Mcf. to be shown than if the contract pressure base of the company were used?

A. Yes, that is correct.

Q. And those figures on Page 5 also are on the same pressure base?

A. They are on the same pressure base.

Q. And again on Page 6 where you have some prices stated?

A. Yes, on the uniform pressure base.

Q. Is that true also of those prices at the top of Page 7?

A. They are on the uniform pressure base of 14.65.

Q. Now if you will turn back to Page 5 with reference to the information at the bottom of the page where you indicate and state that the City of Colorado Springs pays one cent per Mcf. more for gas that it sells to domestic and spaceheating customers and for gas sold at the same city gates of Pueblo and Denver, you no doubt are familiar with the provisions in the Colorado Springs contract under which it would earn certain refunds on the gas for spaceheating, providing certain increases in numbers of customers and volumes were accomplished.

A. Yes.

Q. And in making your study, did you observe that whereas Pueblo and Denver—that is, the Public Service Company of Denver, had made such increases in numbers of customers and volumes of gas that they earned the full 2-cent refund?

A. The Denver and Pueblo earned the full 2-cent refund, yes.

Q. But the City of Colorado Springs has not yet accomplished that thing; that is, they pay a cent more per Mcf.

A. They may be so. The computations is taken directly from the revenues of what actually did take place.

Q. Now, I see what you have done here is just take the actual revenues and relate them without making any attempt to determine whether the schedules were similar or gave them similar rights?

A. The schedule gives them similar rights.

Q. It does?

A. Yes.

Q. Now with respect to the notation you have as to the domestic block of gas for the Citizens Utilities Company and the Arkansas Valley Natural there, those consumers in those towns use less gas per customer than they do other places, do they not?

A. Well, the consumption on the first step is less in the rate than for those towns. I believe they are 1.8 Mcf. instead of the 3 on the first block.

Q. Those are all small communities compared to Pueblo, Colorado Springs and Denver?

A. That's right.

Q. All right, now, if you will turn to Page 9, you make certain reference to certain curtailments of service and have stated that that has never taken place because of the shortage of gas supply in the field, but that there have been certain interruptions because of line breaks and some domestic peak loads.

Now, so far as the industrial customer is concerned, to him the curtailment of his gas is substantially the same thing whether that is caused by a shortage of supply from break in the line or shortage of supply available to him because of increase in demands for domestic customers, would that not be so?

A. Will you read that question, please?

(The question referred to was read by the reporter as set forth above.)

The Witness: As far as he is concerned, that might or might not be so. What I am driving at is that one would be classed an act of God and another one would be at your request due to high domestic peaks.

By Mr. Dougherty:

Q. Well, when you have a break in the line and in order to keep up whatever your domestic load is at that time, then it becomes necessary to shut off or curtail the industries?

A. Yes, that is necessary, too.

Q. That is, whether the lack of capacity is due to increased demands of domestic customers or lack of capacity due to a break which lowers your normal capacity, the result is the same in either event to the industry?

A. Yes, it could be the same.

Q. He doesn't get his gas.

A. I was referring rather to the cause.

Q. I see. Now turn to Page 10, will you, please? You make reference there in the second paragraph; that is, the first full paragraph on the page, that the gas which is sold for resale to the Denver line has preference over that which goes to the Chicago line but that the gas sold to the Chicago line is at a higher price.

Now, so far as the Canadian River Gas Company is concerned, doesn't it get the same price for gas from the Colorado Interstate Gas Company that goes to Chicago as well as to Denver?

A. Since June the 1st, 1938, that is correct.

Q. Previously the statement you made was true; that is, before that date?

A. Before that date, but is true that— well, as far as Canadian River goes, but as far as Colorado Interstate that is not so.

Q. Well, what Colorado Interstate does is sell gas to the Chicago line at a fixed price?

A. That is correct, and it is higher than the average price that is delivered to the two lines.

Mr. Lange: You mean higher than the average price delivered to what lines?

The Witness: To Chicago line than to the Denver line.

* * * * *

Mr. Lester further testified: (Vol. Cl, pp. 15653-15657.)

Q. Mr. Lester, returning to your Exhibits 261 and 262, I will ask you whether or not they contain tables showing interruptions in service, point of delivery, date, customer, duration, and cause?

A. There is a table in there showing that information.

Q. Now, then, these Exhibits 262 and 261 were prepared by you and include matters pertaining to both of these companies down through December 31, 1939?

A. That is correct.

Q. Have you had occasion since the completion of these exhibits to study the history of all interruptions in service of both companies, particularly the information that was set forth in the company's exhibit 290, prepared by Mr. Beardsley?

A. Yes, I have reviewed that exhibit.

Q. Please refer to Exhibit 290 at this time and state what your opinions and conclusions are in connection with the interruptions in service of both companies.

A. There has been no further interruption of the Canadian River Gas Company.

Q. Of the Canadian River Gas Company?

A. Of the Canadian River Gas Company during 1940.

Q. So those interruptions set forth in your Exhibit 261 are all that you have any knowledge of?

A. That is all I have any knowledge of and I commented upon those interruptions.

Q. All right, let us move to the Colorado Interstate Gas Company.

A. In reviewing the information in Exhibit 290, on Table 2 in that Exhibit is a statement of total interruptions in service to December 31, 1940.

Q. That is Table 2 pertaining to which company?

A. The Colorado Interstate Gas Company—I guess there is a mixup on the table numbers in the exhibit.

Q. Is the table the second to the last one in the exhibit?

A. Yes, the second to the last table in the exhibit.

Q. What statement did you have to make with reference to that table?

A. This is the total interruptions of the company and it shows the hours of duration, also indicates the cause for the total interruptions. The cause of the total interruptions in all cases was due to either pipe failure or washout. Washout, of course, is a cause of pipe failure. It is more or less due to the act of Nature.

The main line industrial total interruptions due to physical causes for the 13 years amounted to 111.5 or 1.7 hours per main line industrial customer.

Q. During the entire history of the company?

A. During the entire history of the company. There are also washouts for the Colorado-Wyoming Gas Company and to the city gate included in there. They amounted to 157.5 hours for the entire service of the company.

Q. In the course of the prepartion of these two exhibits you have had all relevant data and records available to you for your inspection?

A. Yes, except the last year.

Q. Except the year 1940?

A. Yes, sir.

Q. Now, then, from your examination of the company's records, particularly those records pertaining to suspensions, interruptions, reduction or interruptions in service, did you find during the entire history of the companies that they lost any customers due to interruptions or suspensions of service?

A. No.

Q. If there had been such a customer loss for any one of those reasons, you would have learned of it in connection with your search of the records?

A. Yes, sir, prior to 1940. I haven't searched the record in 1940.

Q. In so far as 1940 is concerned, does this Exhibit 290, which sets forth reductions and suspensions in service, indicate that any of the customers shown ceased purchasing gas from the company?

A. Not for those causes, no. There is one that has—the Citizens Utilities Company took part of the operation over but they are delivering to all of the city gates and same delivery points during 1940. As to those companies whose

interruptions are referred to there, they are still delivering to them.

Q. Borrowing Mr. Keffer's use of the homely illustration about "proof of the pudding is in the eating," would you say that the proof of the pudding with reference to whether these customers of the company are taking these suspensions, reductions, or interruptions in service, as a reason for not purchasing further supplies of gas is not in this picture?

A. No.

Q. In other words, there has been no loss of customers in so far as you know due to any one or all of those factors?

A. That is correct. There has been none. No loss.

Now turning over to the reduction in there, the reduction to the main line industrials amounts to 1.7 hours per year per main line customer.

Q. And you have heard—or, I'll ask you whether you did hear any of the testimony that was given by either one or more of the rate of return witnesses setting forth the fact that these interruptions or reduction in service were risks that the company had to face in its business?

A. I heard some of them testifying to that.

Q. Well, it didn't result in their loss of any customers so far as you know?

A. No, it did not result in the loss of any customers.

* * * * *

Mr. Lester further testified: (Vol. CI, pp. 15664-15665.)

Q. Mr. Lester, as I understand it, in arriving at the total number of hours of interruptions that you mentioned a moment ago in connection with Mr. Beardsley's Exhibit 290, you merely added up the hours from his exhibit? That was a matter of calculation?

A. That is correct.

Q. You take no exceptions to the accuracy of the data contained in Exhibit 290, do you?

A. Neither pro or con. I don't know. I have accepted it in my additions to be correct.

Q. You were asked by Mr. Lange whether there was any loss in customers as the result of any of these interruptions, I believe, and I think your answer was that there had been none?

A. Yes.

Q. Whose customers did you have in mind when you gave that answer?

A. I had in mind the Colorado Interstate's customers and the Canadian River's customers.

Q. That is all?

A. Yes, that is all.

Q. You didn't have in mind in that answer the customers of any of the distributing companies?

A. No, sir.

Q. So that your only check on that proposition as to whether there had been any loss in customers was to determine, I assume, from the records of the company that the company was continuing to furnish the same customers with gas as heretofore?

A. Yes, it is the same companies that the interruptions referred to.

Witness Lusk, in Exhibit 318, applying the methods and percentages so arrived at by Mr. Rhodes in Exhibit 316, apportioned the costs to Colorado Interstate for gas delivered to it at Clayton Juntion, as between resale and direct sale gas. The costs so to be apportioned are the total costs by operating systems as set forth in Exhibit 164, abstracted under Title 29, supra. Such costs cover (a) costs arising from operating and maintaining the property owned by the company, and (b) payments reimbursing Colorado Interstate, with interest for the funds advanced by it and used in the purchase and development of the property. The method of determining the costs of operations of Canadian is the basic method used in its contract for the sale of gas to Colorado Interstate, in Exhibit 16.

In Mr. Rhodes' Exhibit 316 he did not treat of the apportionment of amortization of debt, interest and Federal taxes. Mr. Lusk, in his Exhibit 318, pointed out that in Exhibit 164 the cost of amortizing the debt to Colorado Interstate was used (in lieu of depletion and depreciation) in accordance with the basic terms of the contract. He therefore concluded that the amortization of debt applicable to leaseholds and the gas well construction is appropriately apportioned to the several classes of business pro rata with

their respective property apportionments, and that amortization of debt applicable to all other property is appropriately apportioned pro rata with the apportionment of the property for which the debt was incurred.

The same method of apportionment was adopted with respect to interest.

With respect to the Federal taxes, Mr. Lusk stated that these taxes, as determined and set forth in Exhibit 164, arise from all classes of business of Canadian, and that they are appropriately apportioned to the several classes of business in proportion to the respective taxable net incomes arising from these classes of business. (Pp. 1 to 3 of Exhibit 318.)

Mr. Lusk then stated that in Exhibits 164 and 167, abstracted supra under Titles 29 and 30, he determined the computed costs under basic contract terms for all gas and for resale gas only under the contract between Colorado Interstate and Canadian of January 3, 1928 (Exhibit 16, which, under Exhibit 164, for all gas was $1,221,008, and under Exhibit 167 for resale gas alone was $954,874, indicating an apparent cost of direct sale gas of $266,134.

As shown on Statement 1 of Exhibit 318, the amount apportioned to direct sale gas in 1939 was $439,497. (P. 4 of Exhibit 318.)

Statements 3 to 8 attached to the exhibit show the detailed apportionment of operating costs under basic contract terms for the year 1939 to the several classes of business, and to resale gas and direct sale gas deliveries to Colorado Interstate at Clayton Junction.

Statement 2 summarizes the apportionment of costs by operating systems for each year from 1928 to 1947, inclusive, by principal classes of business, and by resale and direct sale gas deliveries to Colorado Interstate at Clayton Junction.

Statement No. 1 summarizes Canadian's costs under the basic contract terms of gas delivered to Colorado Interstate at Clayton Junction for resale and direct sale gas as follows:

Canadian River Gas Company

Apportioned Costs of Gas Under Basic Contract Terms Between Resale Gas and Direct Sale Gas Deliveries To Colorado Interstate Gas Company, At Clayton Junction, New Mexico

Summary by Years—1928 to 1947, Inclusive (A)

Year (1)	Resale Gas (2)	Direct Sale Gas (3)	Total (4)
1928 (B)	$ 123,266	$105,650	$ 228,916
1929	483,635	379,429	863,064
1930	956,310	646,666	1,602,976
1931	1,041,655	646,762	1,688,417
1932	902,561	504,860	1,407,421
1933	871,014	477,082	1,348,096
1934	763,112	485,517	1,248,629
1935	706,233	402,846	1,109,079
1936	708,623	465,774	1,174,397
1937	762,301	439,856	1,202,157
1938	817,456	390,354	1,207,810
1939	823,932	435,497	1,259,429
1940	894,520	462,201	1,356,721
1941	885,198	427,550	1,312,748
1942	874,827	405,642	1,280,469
1943	899,824	398,326	1,298,150
1944	885,135	385,442	1,270,577
1945	870,354	373,371	1,243,725
1946	858,444	371,651	1,230,095
1947	1,151,046	565,428	1,716,474

Notes: (A) From Statement No. 2 attached.

(B) 7 Months.

65. Company's Statement as to Revenues Required to be Received from Colorado Interstate on a Regulatory Rate Basis for Gas Delivered at Clayton Junction Apportioned Between Resale Gas and Direct Sale Gas.

Exhibit 317 (Vol. CII, p. 15954), Witness Lusk, is entitled, "Apportioned Revenues from Gas Required on a Regulatory Basis Between Resale Gas and Direct Sale Gas Deliveries to Colorado Interstate Gas Company, at Clayton Junction, New Mexico. Summary by Years 1939 to 1947, Inclusive."

Here again he adopts and applies the methods of apportionment described in Mr. Rhodes' Exhibit 316, and on such basis determines the revenues required from Colorado Interstate for gas delivered at Clayton Junction, apportioned as between resale and direct sale gas.

Mr. Lusk stated that the costs of operation and required revenue to be apportioned are those shown in Exhibit 276, abstracted supra under Title 34.

As Mr. Rhodes, in Exhibit 316, did not treat of the apportionment of depletion, depreciation or amortization, return and Federal income taxes, Mr. Lusk adopted the following methods for the apportionment of these items. As to the apportionment of amortization, he stated that in Exhibit 276 the cost of amortizing the property by 1956 was used in lieu of depletion and depreciation, and that no provision was made for replacing any property except facilities such as drilling and cleaning equipment and automobiles and trucks. The amortization costs applicable to leaseholds and gas well construction were apportioned by Lusk to the several classes of business pro rata with respect to their property apportionment. The amortization costs applicable to all other property were apportioned by Lusk pro rata with the apportionment of the property itself. (P. 1, Exhibit 317.)

As to return, he apportioned it to the several classes of business pro rata with the total amount of property so apportioned.

As to Federal taxes, as determined and set forth in Exhibit 276, he apportioned them to the several classes of business in proportion to the respective taxable net incomes

arising from these several classes of business. (P. 2, Exhibit 317.)

He then referred to Exhibits 276 and 277, where there was determined the required revenues from gas on a regulatory rate basis delivered at Clayton Junction to Colorado Interstate, for all gas and for resale gas only, respectively, which determinations were made under the provisions of the contract of January 3, 1928, between Canadian and Colorado Interstate (Exhibit 16). The required revenue there shown for the year 1939, in Exhibit 276 (all gas), is $1,339,860, and in Exhibit 277 (resale gas alone), $1,051,079, with an apparent cost of direct sale gas in the amount of $288,781.

Following the procedure in the exhibit last above abstracted, Statements 3 to 8 show the detailed apportionment of operating costs and required revenues for the year 1939, as shown in Exhibit 276, to the several classes of business, and between resale and direct sale gas at Clayton Junction.

Statement 2 summarizes the apportionment of costs by operating systems for each year from 1939 to 1947, inclusive, by principal classes of business and by resale and direct sale gas deliveries to Colorado Interstate at Clayton Junction. (P. 4, Exhibit 317.)

Statement 1 summarizes the amounts apportioned in accordance with the methods set forth in Mr. Rhodes' Exhibit 316, that Canadian is entitled to receive on a regulatory rate basis from Colorado Interstate for resale and direct sale gas delivered at Clayton Junction, as follows:

Canadian River Gas Company

Apportioned Revenues Required from Gas on a Regulatory Basis (A) Between Resale Gas and Direct Sale Gas Deliveries

To Colorado Interstate Gas Company, at Clayton Junction, New Mexico

Summary by Years—1939 to 1947, Inclusive

Year (1)	Resale Gas (2)	Direct Sale Gas (3)	Total (4)
1939	$ 920,265	$446,153	$1,366,418
1940	1,051,028	510,927	1,561,955
1941	1,104,761	504,625	1,609,386
1942	1,096,698	482,165	1,578,863
1943	1,165,938	488,910	1,654,848
1944	1,205,216	489,657	1,694,873
1945	1,239,457	488,045	1,727,502
1946	1,288,770	510,559	1,799,329
1947	1,816,663	842,830	2,659,493

Note: (A) Includes an allowance of 8 per cent return on a depleted and depreciated original cost rate base at January 1, 1939, plus additions thereafter at cost, and provision for depletion, depreciation and amortization by a sinking fund method with compound interest at a rate of 2¾ per cent per annum.

66. Company's Statement as to Revenue Required to be Received from Colorado Interstate for Gas Delivered at Clayton Junction Based Upon 7c Per Mcf. Market Value of Gas at Bivins Intake.

Under title 22 supra there has heretofore been abstracted the Company's evidence as to the 4-cent per Mcf. wellhead market value of gas and an estimated 7-cent per Mcf. market value at Bivins Intake after gathering.

Through the WITNESS LUSK there was introduced and received in evidence respondent's Exhibit 321. (Vol. CII, Second Part, page 16020.) Statement No. 2 of Exhibit 321 is shown as follows:

Statement No. 2

Canadian River Gas Company

Required Revenues on a Regulatory Rate Basis from All Gas Sales Based on a Cost of Gas at Bivins Station of 7c per Mcf. (16.4 Lb.)

1939 to 1947, Inclusive

Item No.	Description	1939	1940	1941	1942	1943	1944	1945	1946	1947
1.	Gas Deliveries at Bivins Station—Mcf. Input (Exhibit No. 164, Statement No. 10)	19,351,503	19,835,803	21,386,114	21,872,483	22,005,038	22,457,139	22,905,308	22,905,308	22,905,308
2.	Cost of Gas at 7 Cents per Mcf.	$1,354,605	$1,388,506	$1,497,028	$1,531,074	$1,540,353	$1,572,000	$1,603,372	$1,603,372	$1,603,372
3.	Transmission Cost (Exhibit No. 276, Statement No. 4)	580,934	701,598	725,895	726,264	800,748	831,797	860,667	893,073	933,016
4.	Total Canadian River Gas Co.	$1,935,539	$2,090,104	$2,222,923	$2,257,338	$2,341,101	$2,403,797	$2,464,039	$2,496,445	$2,536,388
	Cost of Gas to C.I.G. Co. at Clayton Junction:									
5.	Per Cent (Exhibit No. 276, Statement No. 4)	97.70%	97.76%	97.91%	97.95%	97.95%	97.99%	98.02%	98.02%	98.02%
6.	Amount	$1,891,022	$2,043,286	$2,176,464	$2,211,063	$2,293,108	$2,355,481	$2,415,251	$2,447,015	$2,486,168

This Statement No. 2 and the other two statements in Exhibit 321 are explained by Mr. Lusk in his testimony. (Vol. 102, Second Part, pages 16010 to 16020.) As indicated by Statement No. 2, the gas deliveries at Bivins Station for the different years, 1939 to 1947, are taken from Exhibit No. 164, Statement No. 10, and the transmission cost from Bivins Station to Clayton Junction, shown on line 3 of Statement 2, is taken from Exhibit No. 276, Statement No. 4.

Exhibit 164, Canadian's WITNESS LUSK, Statement No. 10, column 15, states the actual deliveries of gas by Canadian to Colorado Interstate at Clayton, New Mexico, at 16.4-pound pressure base in Mcf. for the years 1928 to 1947, inclusive, as follows:

Year	Gas Delivered at Clayton to C.I.G. Co. (15)
1928	2,926,886
1929	9,775,441
1930	11,847,757
1931	12,511,839
1932	12,170,499
1933	11,466,028
1934	11,982,834
1935	12,993,828
1936	16,905,187
1937	17,836,960
1938	16,015,373
1939	18,377,500
1940	18,830,639
1941	20,345,148
1942	20,807,395
1943	20,915,828
1944	21,343,807
1945	21,767,854
1946	21,767,854
1947	21,767,854

Cross-examination of WITNESS LUSK has been abstracted under title 40 supra.

Transcript of record filed September 9, 1942.

And thereafter the following proceedings were had in said cause in the United States Circuit Court of Appeals for the Tenth Circuit:

Order of Submission.

Sixth Day, September Term, Tuesday, September 14th, A. D. 1943. Before Honorable Sam G. Bratton, Honorable Walter A. Huxman and Honorable Alfred P. Murrah, Circuit Judges.

These causes came on to be heard, Elmer L. Brock, Esquire, and E. R. Campbell, Esquire, appearing for Colorado Interstate Gas Company; John P. Akolt, Esquire, and Charles H. Keffer, Esquire, appearing for Canadian River Gas Company; Donald C. McCreery, Esquire, appearing for Colorado-Wyoming Gas Company; Edward H. Lange, Esquire, appearing for Federal Power Commission; Thomas H. Gibson, Esquire, appearing for City and County of Denver.

Thereupon argument was commenced by counsel and continued to the hour of adjournment.

Order of Submission.

Seventh Day, September Term, Wednesday, September 15th, A. D. 1943. Before Honorable Sam G. Bratton, Honorable Walter A. Huxman and Honorable Alfred P. Murrah, Circuit Judges.

These causes came on further to be heard, Elmer L. Brock, Esquire, and E. R. Campbell, Esquire, appearing for Colorado Interstate Gas Company; John P. Akolt, Esquire, and Charles H. Keffer, Esquire, appearing for Canadian River Gas Company; Donald C. McCreery, Esquire, appearing for Colorado-Wyoming Gas Company; Edward H. Lange, Esquire, appearing for Federal Power Commission; Thomas H. Gibson, Esquire, appearing for City and County of Denver.

Thereupon argument by counsel was concluded and the causes were submitted to the court.

Opinion.

[May 16, 1944.]

Elmer L. Brock and E. R. Campbell (Wm. A. Dougherty and C. W. Cooper were with them on the brief) for Petitioner, Colorado Interstate Gas Company.

John R. Akolt and Charles H. Keffer (P. C. Spencer was with them on the brief) for Petitioner, Canadian River Gas Company.

Donald C. McCreery (Lee, Shaw and McCreery, and Wm. A. Bryans, III, were with him on the brief) for Petitioner, Colorado-Wyoming Gas Company.

Edward H. Lange (Charles V. Shannon, L. W. McKernan, and Milford Springer were with him on the brief) for Respondent, Federal Power Commission.

Thomas H. Gibson (Malcolm Lindsey was with him on the brief) for Respondent, City and County of Denver, Colorado.

Before BRATTON, HUXMAN and MURRAH, Circuit Judges.

BRATTON, Circuit Judge:

These cases bring here for review orders of the Federal Power Commission requiring Canadian River Gas Company, Colorado Interstate Gas Company, and Colorado-Wyoming Gas Company to make reductions in their respective rates for natural gas transported in interstate commerce and sold for resale for ultimate public consumption. Reference will be made to the companies as Canadian, Colorado, and Wyoming, respectively.

The City and County of Denver filed with the Commission a complaint charging that the rates of Canadian, Colorado, and Public Service Company were unjust and unreasonable; similarly, the Public Service Commission of the State of Wyoming filed with the Commission a complaint charging that the rates of Wyoming were unjust and unreasonable; and the Commission instituted on its own motion an investigation into the reasonableness of the rates of Canadian, Colorado, and Wyoming. Canadian and Colorado filed with the Commission their joint application for

a stay of the order directing that the investigation be instituted; the Commission denied the application; the companies sought review; and it was denied on the ground that the order was merely preliminary and procedural and therefore not open to review. Canadian River Gas Co. v. Federal Power Commission, 110 F. (2d) 350, 113 F. (2d) 1010, certiorari denied, 311 U. S. 693. By order of the Commission, the three proceedings were consolidated for purposes of hearing. At the conclusion of extended hearings, the Commission found that the revenues and costs of the companies for 1939 were fairly representative of the relationship which would exist between such items in the immediate future, and that use of the figures for that year resolved most of the doubts as to future operation conditions in favor of the companies. Using the figures for 1939, the Commission determined that the rates and charges of Canadian for gas sold to Colorado and Clayton Gas Company were unjust and unreasonable to the extent of $561,000 annually; that the rates and charges of Colorado were unjust and unreasonable in the amount of $2,065,000 annually; and that those of Wyoming were unjust and unreasonable in the sum of $119,000. The Commission ordered the companies to reduce their rates and charges by not less than such amounts, respectively, and directed that schedules of rates be filed effecting such reductions. The companies applied for a rehearing; the Commission denied the applications; and the companies severally sought review.

Southwestern Development Company, through its wholly owned subsidiary, Amarillo Oil Company, owned gas leaseholds in more than 315,000 acres of land in the Texas Panhandle Field; Cities Service Company, through its wholly owned subsidiary, Public Service Company, at Denver, Colorado, and its wholly owned subsidiary, Pueblo Gas and Fuel Company, at Pueblo, Colorado, controlled the resale market for gas in the two cities, but did not have an adequate supply of natural gas or pipeline facilities for the transportation of natural gas to such cities. After extended negotiations, Southwestern, Cities Service, and Standard Oil Company of New Jersey, entered into an agreement denominated "Memorandum of Stipulations", and dated April 5, 1927. The primary objectives of the contracting parties, as expressed in the agreement, were

the acquisition of natural gas properties in the gas field, the construction of a pipeline from the field to the City of Denver via Pueblo and Colorado Springs, the sale and delivery of natural gas at the city gate of Denver and other cities for distribution in such cities, and the supplying of natural gas to Colorado Fuel and Iron Corporation at Pueblo. Under the terms of the contract, Southwestern was to cause to be transferred to a new wholly owned subsidiary the leaseholds and gas producing properties, and to develop such properties into a source of supply of natural gas; Standard was to cause a corporation to be formed which would construct and maintain a natural gas pipeline and appurtenant facilities for the transmission and sale of gas; and Cities Service, through its subsidiaries, was to obtain franchises and rate ordinances in Denver and Pueblo, respectively, for the sale of natural gas, and convert the artificial gas distribution plants then in use in such cities into natural gas distribution plants. The newly formed subsidiary of Southwestern was to sell at cost gas to the pipeline company; and, with provisions for revision which need not be detailed, the pipeline company was to sell and make delivery at the city gate at the rate of forty cents per thousand cubic feet. The producing company and the pipeline company, and the pipeline company and the distributing companies, were to enter into contracts carrying out the commitments made in the Memorandum of Stipulations; and such contracts were to be for a term of twenty years from and after the execution of the first thereof, and as long thereafter as natural gas might be profitably sold by the pipeline company. The contract further provided that in case an acceptable rate ordinance was not secured in the City of Denver, on or before July 1, 1927, the parties thereto, or any of them, might terminate participation therein, and each thereupon be free to act as though such stipulations and any agreements thereunder had never been made.

Franchises and rate ordinances were obtained in Denver and Pueblo; Canadian was incorporated as the subsidiary of Southwestern; and Standard caused Colorado to come into existence. Canadian and Colorado, Colorado and Public Service Company, and Colorado and Pueblo Gas and Fuel Company, respectively, entered into contracts as pro-

vided in the Memorandum of Stipulations; and by contractual arrangements, Colorado obligated itself to sell natural gas to the City of Colorado Springs for distribution by the city in its municipally owned distribution system and for sale to industrial and commercial consumers. Southwestern caused Amarillo Oil Company to convey the leases to Canadian. Canadian paid Amarillo Oil Company the sum of $5,000,000 for the leases and the then producing wells. Southwestern and Standard had agreed upon that amount, and it was paid with funds furnished by Standard. Canadian was financed through the issuance of bonds in the amount of $11,000,000, all of which were purchased by Colorado with funds furnished by Standard. Colorado issued 1,250,000 shares of common stock without par value, of which forty-two and one-half per cent was issued to Southwestern, forty-two and one-half per cent to Standard, and fifteen per cent to Cities Service; and it issued preferred stock valued at $2,000,000, one-half to Standard and one-half to Southwestern. Standard paid Colorado $1,000,000 in cash for the common stock issued to it and a like sum for its preferred stock. No cash consideration was paid for the stock issued to Southwestern or Cities Service. Colorado issued bonds in the amount of $19,200,000. These were sold to Standard for cash at par, and the proceeds, along with the cash which Standard paid for the stock issued by Colorado, aggregating $21,200,000, was used to finance the project. Canadian developed the leaseholds, and constructed a main transmission pipeline from the field to Clayton Junction in New Mexico, a distance of approximately 86 miles; and Colorado constructed a main transmission line from Clayton Junction to the city gate at Denver, a distance approximating 254 miles, three compressors, and various laterals extending from the main line to customers of the company, including a lateral to the plant of Colorado Fuel and Iron Corporation. On December 31, 1939, Canadian had in operation a total of 94 gas wells; and its gathering system consists of about 144 miles of pipe, and has two terminals. One terminal is located at the Bivins Station where the gas there gathered is compressed and then transmitted through the transmission line to Clayton Junction where virtually all of it is sold to Colorado but a small amount is sold to Clayton Gas Company.

The other terminal is located at Fritch Station where the gas there gathered is compressed and then transported through the facilities of Texoma Natural Gas Company to Gray Junction, in Oklahoma, where it is sold to Colorado. Colorado sells that gas to Natural Gas Pipeline Company, and it moves to its destination, known as the Chicago market.

The facilities of Wyoming consist of a main transmission pipe line extending from a point near Littleton, Colorado, to the city gate at Cheyenne, Wyoming, compressor stations, and a number of laterals extending from the main line to city gates and industrial plants in Colorado and Wyoming. From the inception of the project until the latter part of 1929, the company obtained its entire supply of natural gas from the Wellington Field in Colorado. But early in 1929, the supply from that field began diminishing rapidly; it became essential that the company secure another source in order to continue in business; in October of that year, it entered into a contract with Colorado for the purchase of gas from that company with which to supply its customers in the States of Colorado and Wyoming; and ever since Colorado has sold gas to Wyoming, deliveries being made at the point adjacent to Littleton.

In 1939, Canadian sold for resale approximately 46,000,000 Mcf of gas, of which about 41,000,000 Mcf were sold to Colorado; Colorado sold about 20,000,000 Mcf of such gas to Natural Gas Pipeline Company, about 7,000,000 Mcf to Colorado Fuel and Iron Corporation, and about 6,000,000 Mcf to Public Service Company; and Wyoming transported and sold 2,860,000 Mcf, some to affiliates for resale through distribution systems in towns and communities in Colorado and Wyoming, some to other companies for like distribution, some to industrial consumers, and some to United States Army posts.

The Motions to Dismiss—The City and County of Denver filed separate motions to dismiss the petitions for review of Canadian and Colorado, and Public Service Commission of Wyoming filed a like motion to dismiss the petition for review of Wyoming. We denied the motions, but thereafter the City and County filed a brief, and later its counsel participated in the oral argument, renewing the con-

tention that the petitions should be dismissed for want of jurisdiction. The grounds of each motion are that it appears from the face of the petition for review that the petitioning company is a private corporation organized and existing under the laws of Delaware; that the petition fails to allege that the company is located in this circuit; and that it affirmatively appears from the face of the petition, the face of the record, the testimony of the company's own witnesses, and facts dehors the record that the company is not located and does not have its principal place of business in this circuit. These companies were incorporated under the laws of Delaware, and therefore their legal residence and domicile is in that state. Shaw v. Quincy Mining Co., 145 U. S. 444; Southern Pacific Co. v. Denton, 146 U. S. 202; Home Powder Co. v. Geis, 204 F. 568; Continental Coal Corp. v. Roszelle Bros., 242 F. 243; Dryden v. Ranger Refining & Pipe Line Co., 280 F. 257, certiorari denied, 260 U. S. 726; In re Hudson River Navigation Corp., 59 F. (2d) 971.

But section 19(b) of the National Gas Act, 52 Stat. 821, 15 U.S.C.A. § 717r(b), provides that any party to a proceeding under the act who is aggrieved by an order of the Commission made in the proceeding may obtain a review of the order in the Circuit Court of Appeals of any circuit in which the natural gas company to which the order relates is located or has its principal place of business, or in the Court of Appeals of the District of Columbia, by filing in such court within the time specified a petition in writing praying that the order be modified or set aside in whole or in part. It is to be noted that the statute provides in clear language that review may be had either in the circuit where the company is located or in the circuit where its principal place of business is located, the pivotal language being stated in the disjunctive. It is commonplace for a corporation chartered in one state to conduct much or all of its business in another state far distant from that of incorporation. No doubt mature considerations of convenience gave rise to the deliberate care with which Congress, in the exercise of its discretion, authorized review in the circuit within which the principal business of the company is conducted. And the principal place of business is where the actual business of the corporation is conducted or trans-

acted. It is a question of fact to be determined in each particular case by taking into consideration such factors as the character of the corporation, its purposes, the kind of business in which it is engaged, and the situs of its operations. Cf. In re Guanacevi Tunnel Co., 201 F. 316; In re Hudson River Navigation Corp., supra; Chicago Bank of Commerce v. Carter, 61 F. (2d) 986.

Section 5, chapter 65, Revised Code of Delaware, provides that the certificate of incorporation shall set forth the name of the county, and the city, town, or place within the county, in which the principal office or place of business of the corporation is located in that state; and section 32 provides that every corporation shall maintain a principal office or place of business in the state. Here, in each instance, the certificate of incorporation states the location of the principal office of the company in Delaware, but it is completely silent in respect of the place of business. All of the physical properties and business operations of Colorado and Wyoming are located and conducted within this circuit. Wyoming maintains offices in Denver where its executive officers and agents supervise and administer its properties and operations. Canadian transports almost ninety per cent of the natural gas which it produces into this circuit, part into New Mexico and part into Oklahoma, where virtually all of it is sold to Colorado.[1] The properties of Canadian and Colorado are operated as a unit. The two companies have a single general manager and jointly maintain an office in Colorado Springs, under the charge of such manager, where the supervision, direction, and management of the affairs of both companies are conducted. There are approximately thirty-six employees in the office, some devote their entire time to the business of Colorado and are paid by that company, some divide their time between the business of the two companies, and their salaries are paid partly by each company. The general manager is in charge of all operations of Canadian, including the gas fields and a field operating office in Texas; the chief dispatcher, who keeps in constant touch with the expected demands for gas and gives orders for the amount of gas to be piped, has his office in Colorado Springs and is under the supervision of the general manager. The principal books of account are kept in Colorado

Springs, under the direction of the assistant treasurer of the company who maintains his office there. All major purchases for both companies are made and all bills for materials purchased are paid by vouchers issued out of the office there; all dealings between the two companies in connection with the purchase and sale of gas are conducted in and through the office there; and the principal bank account of Canadian is kept in banks in that city. We think it is clear that the principal place of business of each company is in this circuit, within the meaning of the statute. Continental Coal Corp. v. Roszelle Bros., supra; Dryden v. Ranger Refining & Pipe Line Co., supra; In re Lone Star Shipbuilding Co., 6 F. (2d) 192. And we therefore adhere to the view that the motions to dismiss are illfounded.

Jurisdiction of Production and Gathering Properties—Canadian attacks the order relating to the reduction in its rates and charges on the ground that the Commission erroneously undertook to exercise unauthorized rate-regulatory jurisdiction over the production and gathering properties, facilities and business of the company. Section 1(a) of the Act, supra, declares "that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation . . . relating to the transportation of natural gas and the sale thereof in interstate . . . commerce is necessary in the public interest". Section 1(b) limits the act in its application "to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale", and further provides in express terms that it "shall not apply . . . to the production or gathering of natural gas." Section 2(6) provides that a natural gas company is a company engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale. Section 4(a) declares that rates and charges in connection with the transportation of natural gas subject to the jurisdiction of the Commission "shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful". Section 5(a) directs the Commission to

"determine the just and reasonable rate . . . and shall fix the same by order". Section 6(a) empowers the Commission to "investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property". Section 7 vests in the Commission certain powers relating to the improvement, establishment of physical connections, abandonment, construction, or extension of transportation facilities of natural gas companies. Section 8 enables the Commission to require natural gas companies to keep and maintain accounts and records. Section 9 charts the authority of the Commission in relation to rates of depreciation and amortization of the several classes of property of natural gas companies. Section 10 concerns the filing with the Commission of periodic and special reports. Section 11 is addressed to the duties of the Commission respecting state compacts dealing with the conservation, production, transportation, or distribution of natural gas. And section 14(a) authorizes the Commission to "investigate any facts, conditions, practices or matters which it may find necessary or proper to determine whether any person has violated or is about to violate any provision of this Act." The primary legislative purpose in the passage of the Act was to provide comprehensive regulation of the wholesale distribution to public service companies of natural gas moving interstate, and to vest in the Commission as the instrumentality of Congress power to exercise such regulation. Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U. S. 498; Public Utilities Commission v. United Fuel Gas Co., 317 U. S. 456. And the grant of powers expressly conferred upon the Commission carried with it by implication all authority reasonably necessary and fairly appropriate to make such powers fully efficacious, and to render effectual the discharge of the duties of the Commission. But, under section 1(b) the Commission does not have express or implied rate-regulatory jurisdiction of the production and gathering of gas.

Canadian is engaged in the business of producing, gathering, transporting and selling interstate natural gas for

resale for ultimate public consumption. It therefore is a natural gas company, subject to the jurisdiction of the Commission in respect to its rates and charges for the gas transported and sold in such commerce. Its production and gathering properties and facilities are parts of its integrated operations. Still, under section 1 of the Act they lie beyond the range of the rate-regulatory jurisdiction of the Commission. But the Commission did not prescribe charges for the production; did not fix rates for the gathering of gas; and did not exercise other rate-regulatory jurisdiction over production or gathering as such, within the meaning of the limiting and forbidding provisions of the Act. The Commission did not attempt to affect in any manner the acquiring and maintaining of gas leaseholds, gas rights, or gas wells. Neither did it undertake to affect anywise the location, construction, extension, or physical connections of pipelines, or the operation of pipelines or other facilities constituting the gathering properties. The rate-regulatory jurisdiction of the Commission was exerted only in respect of rates and charges for natural gas transported in interstate commerce and sold in such commerce for resale for ultimate public consumption. The Commission inquired into and considered the production and gathering properties in respect to cost, depreciation, operating expenses, and revenues. But the inquiry was merely in their relation to the fixing of reasonable rates to be exacted and received for the natural gas moved in interstate commerce and sold for resale. And the order of the Commission in each instance operated only upon such rates and charges. We fail to find in the act anything which expressly or by fair implication indicates a Congressional purpose to restrict or withhold from the Commission jurisdiction in a case of this kind to take into consideration the production and gathering properties only as they have bearing upon the question of the fixing of reasonable rates for gas moved interstate and sold for public consumption.

Abrogation of Prices Fixed by Contract Prior to Effective Date of the Act—While not challenging the constitutional validity of the Act on its face, or as it may be applied in general, Canadian and Colorado advance the contention that here the Commission erred in applying it retrospectively in such manner as to abrogate prices

agreed upon in contracts of limited term entered into and substantially performed prior to the enactment of the Act, at a time when neither company was in fact or in law a utility or common carrier, and when each disclaimed all of the privileges and obligations as such. The contracts between Canadian and Colorado, Colorado and Public Service Company, Colorado and Pueblo Gas and Fuel Company, Colorado and the City of Colorado Springs, and Colorado and Wyoming, respectively, were each executed prior to the date on which the act became effective; they were of limited term; and they had been performed in substantial part at the time the Act went into effect. But at all times, the transportation and sale of natural gas in interstate commerce for wholesale distribution to public service companies or municipalities for resale to domestic consumers was subject to regulation by Congress. Missouri v. Kansas Gas Co., 265 U. S. 298; Illinois Natural Gas Co. v. Central Illinois Public Service Co., supra; Federal Power Commission v. Natural Gas Pipeline Co., 315 U. S. 575; Public Utilities Commission v. United Fuel Gas Co., supra. And the exertion of the power of Congress in its regulation of interstate commerce is not fettered by pre-existing contracts or arrangements. The exercise of power under the Commerce Clause cannot be subordinated to arrangements or stipulations previously effected. Contracts and arrangements of that kind necessarily are entered into with knowledge of the paramount authority of Congress to regulate commerce among the states. Union Bridge Co. v. United States, 204 U. S. 364; Monongahela Bridge v. United States, 216 U. S. 177; Philadelphia Co. v. Stimson, 223 U. S. 605; Philadelphia, Baltimore and Washington Railroad Co. v. Schubert, 224 U. S. 603; Greenleaf Lumber Co. v. Garrison, 237 U. S. 251; Continental Co. v. United States, 259 U. S. 156; Sproles v. Binford, 286 U. S. 374; Radio Commission v. Nelson Bros. Co., 289 U. S. 266.

It is emphasized that at the time the contracts were entered into neither of these companies was in fact or in law a public utility or common carrier, and that each disclaimed all of the privileges and obligations as such. These companies have never sought or acquired any certificate of public convenience and necessity, any franchise, or any right to enter a municipality; they have never advertised or rep-

resented that they would sell gas to the public generally; and they have never filed any rate schedule with any regulatory commission or any other authority. At the time the Act became effective, and since, Canadian transported and sold interstate gas to Colorado, and also made sales for resale to a distributing company; and Colorado made sales for resale to one municipality, four or five distributing companies, and two pipelines, and made direct sales to five industrial customers, under private contracts respecting price, quantity, time of delivery, and so forth. But freedom of contract does not place it within the power of companies engaged in business of that kind to restrict or withhold from the control of Congress at a later time so much of the field of regulation of interstate commerce as they choose to bring within the range of their arrangements. Even though executed prior to the enactment of the Act, contracts of that nature are subject to regulation in the public interest. Cf. Mississippi River Fuel Corp. v. Federal Power Commission, 121 F. (2d) 159.

The companies made large investments on the strength of the contracts but that is not decisive, as in the very nature of things they were made subject to the exercise of the paramount authority of regulation. Radio Commission v. Nelson Bros. Co., supra.

Requiring the Impossible of Canadian—Canadian attacks the order relating to its rates and charges on the further score that it requires the company to do the impossible, and violates due process. The contract between Canadian and Colorado requires Canadian to develop, operate, and maintain its properties with diligence, so as to produce sufficient natural gas to meet the requirements of Colorado; to sell the gas to Colorado at cost; to make no contract for the sale of gas that might impair its capacity to produce gas for delivery to Colorado; to credit Colorado with all revenues, income, or profits which it may receive from any other source; and to disburse funds received from any source only in the discharge of its obligations under the contract with Colorado and any other contracts permitted under its provisions, and in payment of principal and interest on its outstanding indebtedness. It is argued that the contract forecloses any possibility of profit to Canadian

and therefore the order exacts the impossible and is confiscatory. The power to regulate commerce is subject to the limitations and guarantees of the Constitution. Monongahela Navigation Co. v. United States, 148 U. S. 312; United States v. Chicago, Milwaukee, St. Paul and Pacific Railroad Co., 282 U. S. 311. But permissible regulation of rates does not insure that the business shall produce net revenues, and any rate may be decreased which is not the lowest reasonable rate. Federal Power Commission v. Natural Gas Pipeline Co., supra.

This contention in its entirety proceeds upon the premise that since Canadian under the contract sells gas to Colorado at cost, there is no possibility of profit accruing to Canadian. But apparently the argument fails to give consideration to the fact that in connection with the contract under which Canadian furnishes and Colorado accepts the gas, Canadian received initially $5,000,000 in cash from Standard; that Colorado without cash consideration issued to Southwestern forty-two and one-half per cent of all its common stock, and preferred stock of the value of $1,000,000; that Southwestern shares on that basis in the beneficial ownership of Colorado and in its net earnings from time to time; and that in view of the relation existing between Southwestern and Canadian, Canadian in effect shares accordingly. Taking these and other factors into account, there is no basis for challenging the order on the ground that it exacts the impossible and is confiscatory.

The Sufficiency of the Evidence to Support the Finding of Unreasonableness of Rates and Charges—The finding of the Commission that the rates and charges of the companies were unjust and unreasonable is questioned for want of substantial evidence to support it. The passage of the Act did not automatically overthrow the contracts into which these companies had previously entered. Neither did it *ipso facto* set aside the schedules of charges upon which they had agreed. Such rates and charges could be modified only after an express finding of unreasonableness. Wichita Railroad & Light Co. v. Public Utilities Commission, 260 U. S. 48; Allen W. Hinkel Dry Goods Co. v. Wichison Industrial Gas Co., 64 F. (2d) 881. And the right of the Commission to make a finding of unreasonableness

depends upon the existence of the fact. In the absence of substantial evidence to show that the rates and charges in existence are unreasonable, a finding to that effect constitutes the arbitrary exercise of power by administrative fiat and cannot stand. Interstate Commerce Commission v. Louisville and Nashville Railroad Co., 227 U. S. 88.

But a finding of unreasonableness made after a full hearing carries with it a presumption of correctness, and the burden rests upon him who attacks it on review for want of substantial evidence to show the absence of such evidence. An extended analysis of the voluminous evidence would not serve any useful purpose as no two cases of this kind are alike in point of fact. We are content to say that a careful examination of the entire record convinces us that the finding is supported by substantial evidence, and therefore under section 19(b) of the Act, it is conclusive.

The Question of Value—Coming to the question of the rate base, Canadian and Colorado each submitted evidence tending to show reproduction cost new, less observed depreciation, and they also submitted evidence as to the original cost of the property. Wyoming introduced evidence as to actual construction costs, less observed depreciation, plus working capital and additions to plant. The evidence of the Commission staff was restricted to original cost. After considering the estimates of reproduction cost new, less observed depreciation, the Commission concluded that they were too conjectural to have probative value, as they were not based upon established facts, but were subject to the vagaries of theories and imagination. Turning to the evidence of original cost, the Commission found that the properties were all of comparatively recent acquisition or construction; that the accounting records had been sufficiently adequate and well maintained to permit a ready determination of all costs involved; that the major portion of all cost of Canadian and Colorado had been incurred since the adoption by such companies of an accounting system based on the Code of Accounts of the Public Service Commission of Pennsylvania; that the basic facts were clear and essentially undisputed; that they represented the best and only reliable evidence respecting property values; and that, in accordance with section 6 of the act, supra, and under the record in the proceeding, no necessity existed to consider

other factors than original cost. The Commission then determined original cost as of December 31, 1939, deducted a sum representing accrued depreciation, depletion, and amortization, added an amount for working capital and additions to plant, and in the case of Wyoming made a deduction for customer contributions. The amount reached by that method of computation, denominated by the Commission as prudent investment, was adopted as the rate base. The companies contend that the rate base should have been grounded upon present fair value. It must be conceded that the contention finds support in many cases holding that while actual cost, cost of reproduction new, and other elements affecting value should be taken into account and given their proper weight, the final basis of calculation in the regulation of rates of a public utility is a fair return upon the present fair value of the property used for the convenience of the public. Smyth v. Ames, 169 U. S. 466, 546; San Diego Land Co. v. National City, 174 U. S. 739, 757; San Diego Land & Town Co. v. Jasper, 189 U. S. 439, 442; Wilcox v. Consolidated Gas Co., 212 U. S. 19, 41; The Minnesota Rate Cases, 230 U. S. 352, 434; Southwestern Bell Telephone Co. v. Public Service Commission, 262 U. S. 276, 287; Bluefield Water Works & Improvement Co. v. Public Service Commission, 262 U. S. 679, 690; Board of Public Utility Commissioners v. New York Telephone Co., 271 U. S. 23, 31; McCardle v. Indianapolis Water Co., 272 U. S. 400, 410; St. Louis & O'Fallon Railway Co. v. United States, 279 U. S. 461, 484; Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U. S. 287, 305.

But the late case of Federal Power Commission v. Natural Gas Pipeline Co., supra, involved an order of the Commission reducing the rates of two companies engaged in business as a single enterprise in the production and transportation interstate of natural gas for sale at wholesale to public utilities, and the court there held that the "Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. Once a fair hearing has been given,

proper findings made and other statutory requirements satisfied, the courts cannot intervene in the absence of a clear showing that the limits of due process have been overstepped. If the Commission's order, as applied to the facts before it and viewed in its entirety, produces no arbitrary result, our inquiry is at an end." And the later case of Federal Power Commission v. Hope Natural Gas Co., 320 U. S. 591, similarly involved an order of the Commission requiring a reduction in rates of a company engaged in the business of producing, purchasing, transporting and selling at the state line natural gas for continuous movement and ultimate distribution in other states. There the rate base adopted by the Commission was substantially identical with that here; and there, as here, it was attacked on the ground that present fair value is the only permissible rate base. But the court rejected the contention and upheld the order. In doing so, the court said that, "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling . . . . It is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important." These two cases are controlling. And guided by them, it is clear that neither of these orders is to be invalidated for failure of the Commission to use present fair value as the rate base, unless in its totality it oversteps the limits of due process.

Disallowances in Arriving at Original Cost—In arriving at the original cost of the properties, the Commission eliminated certain items appearing on the books of the companies. Canadian paid to Amarillo Oil Company the sum of $5,000,000 in cash for the leaseholds. Their original cost to Amarillo Oil Company was only $1,879,504. Since Canadian and Amarillo were wholly owned subsidiaries of Southwestern, the Commission eliminated $3,120,496, representing the difference between the cost to Amarillo Oil Company and the amount which Canadian paid. By the Memorandum of Stipulations, Southwestern, the parent of Canadian and Amarillo Oil Company, obligated itself to cause the leaseholds to be devoted to the proposed project.

Disregarding the fiction of separate corporate entity, and looking to substance, the contention that the leaseholds should be included at the figure which Canadian paid Amarillo Oil Company rather than the original cost to Amarillo Oil Company amounts in substance to receiving a return on $5,000,000 for property which actually cost less than $2,000,000. There is no proper place in the field of rate-making for synthetic inflation of that kind. Pennsylvania Power & Light Co. v. Federal Power Commission, 139 F. (2d) 445.

As to Colorado, the Commission eliminated $2,352,940, representing the recorded value of stock payments made to Southwestern and Cities Service for entering into contracts for the sale and purchase of gas. By the Memorandum of Stipulations, Southwestern was obligated to require its subsidiary, Canadian, to enter into a contract to sell gas to Colorado, and Cities Service was similarly obligated to require its subsidiaries, Public Service Company and Pueblo Gas and Fuel Company, each, to enter into a contract for the purchase of gas from Colorado. But, according to the records of Colorado, Canadian refused to enter into the contract for the sale of gas to Colorado, and Cities Service refused to direct or permit its subsidiaries to enter into the contracts for the purchase of gas from Colorado; and thereupon Colorado issued to Southwestern as the nominee of Canadian 10,000 shares of preferred and 531,250 shares of common stock, and issued to Cities Service 187,500 shares of common stock. The resolution of the Board of Directors of Colorado authorizing the issuance of such stock recited that the stock first described be issued as part of the consideration for Canadian entering into the contract, and the stock last described be issued in consideration of Cities Service directing its subsidiaries to enter into contracts. The record offers little or no explanation of the refusal to enter into the contracts as provided with binding effect in the Memorandum of Stipulation, or of the failure of Colorado to exact that they be entered into without additional consideration or inducement. Though the reasons may have been satisfactory to the parties in interest, it is manifest that the legitimate cost of Colorado's property for rate-base purposes could not be swelled by the issuance of

stock in circumstances of that kind. Cf. Northwestern Electric Co. v. Federal Power Commission, 321 U. S. 119.

As to Wyoming, the Commission rejected $82,792.57, representing sums paid to Henry L. Doherty & Company for engineers fees. Wyoming and the Doherty Company maintained a contractual arrangement under which the Doherty Company placed at the service of Wyoming its combined experience, advice, and assistance in solving such problems as might arise in connection with the conduct of the business of Wyoming. The tendered advice and assistance related to numerous services, including designing and construction engineering, and fixed the compensation for each, including an engineering fee equal to five per cent of the cost of construction. An affiliate relationship existed between the two companies; Wyoming was unable on request to furnish the Commission any showing that any cost had been incurred in connection with the rendering of engineering services; and there was testimony that the books and records of Wyoming failed to contain any indication that the fees represented any actual cost of services for which the amount was paid. In short, there was no showing satisfactory to the Commission that any engineering services were rendered. The general rule in rate-making against profits in connection with transactions between affiliates warranted the Commission in eliminating the item. Cf. Pennsylvania Power & Light Co. v. Federal Power Commission, supra.

The Commission eliminated from the capital account of Canadian the sum of $129,032, being expenditures previously charged to current operating expense but now sought to be capitalized; it made a like deduction of $440,050 from the account of Colorado; and that action is challenged. In each instance the company added or sought to add the amount in arriving at its claimed original cost. The amount represented reaccounting rather than the correction of accounting, for the charges were made to operating expense in conformity with the established accounting policy of the company in effect at the time, and they were never considered capital investment until the Commission began its investigation. In respect of many expenditures there is at best an indistinct line of demarca-

tion between operating costs and capital costs. It often is difficult to blueprint a clear distinction between expenditures made for operation and maintenance and those made for construction. And therefore a natural gas company, as defined by the Act, must be allowed to exercise a measure of discretion in making its determination between the two. But a method, reasonably acceptable to good accounting, must be adopted and adhered to consistently. Consistent principles and practices of accounting must be followed. Change cannot be made at will. These companies deliberately exercised their discretion in charging these expenditures to expenses; Canadian has fully recovered from Colorado its expense now sought to be capitalized; and Colorado has treated its expenditures now in question as necessary operating expense to be deducted from earnings before arriving at net profits. The Commission was well within the ambit of its authority in making the deductions on the ground that it would do violence to recognized principles of equity to permit these companies at this late hour to shift their position and treat retroactively these items as capital investment upon which they are entitled to receive return. Cf. Federal Power Commission v. Natural Gas Pipeline Co., supra; Northwestern Electric Co. v. Federal Power Commission, 125 F. (2d) 882, affirmed, 321 U. S. 119; City of Wheeling v. National Gas Co., 175 S. E. 339; Peoples Gas Light & Coke Co. v. Slattery, 25 N. E. (2d) 482.

The Commission made a deduction of $366,507 from the original cost claimed by Canadian for interest during construction, and that action is challenged. Canadian recorded on its books a charge for interest during construction, computed on the basis of a construction period beginning May 1, 1927, and ending October 31, 1928, and including the full amount which Canadian paid Amarillo Oil Company for the leaseholds. The Commission found that regular deliveries of gas commenced the latter part of June, 1928, and continued thereafter. The Commission determined that the construction period ended July 1, 1928, and disallowed interest after that date. The books of Wyoming showed the capitalization of interest during construction. The amount included interest on main line construction and on lateral construction. The Commission disallowed the claim in part on the ground that it represented interest computed on a

proportion of the total cost of the property, estimated by the company to be in excess of that required to handle the business actually done during the period. The Commission characterized the claim as the capitalization of a fictitious and arbitrary amount after the close of the construction period, and stated that interest ceases to be a cost of the original plant when commercial operations begin. These companies were not entitled to interest after the construction period ended and they began to receive earnings. Alabama Power Co. v. McNinch, 94 F. (2d) 601.

Elaboration is unnecessary concerning the disallowance of interest on the amount which Canadian paid Amarillo Oil Company for the leaseholds in excess of the original cost to Amarillo Oil Company. We have previously said that, due to the affiliate relation between Canadian and Amarillo Oil Company, the Commission in arriving at the original cost providently included the property at the amount of the original cost to Amarillo Oil Company. That being its cost for rate-base purposes, it follows that interest on the excess could not be included in the rate base.

The Claim for Going Concern Value—Wyoming claimed an allowance for going concern value as part of its rate base. In rejecting the claim and failing to make any allowance for that element, the Commission found that the amount claimed represented a judgment figure wholly unrelated to any costs or outlays, and was therefore deemed unjustified. It is well settled "that there is an element of value in an assembled and established plant, doing business and earning money, over one not thus advanced" and that such "element of value is a property right, and should be considered in determining the value of the property, upon which the owner has a right to make a fair return when the same is privately owned although dedicated to public use." Des Moines Gas Co. v. City of Des Moines, 238 U. S. 153, 165; City and County of Denver v. Denver Union Water Co., 246 U. S. 178, 191, 192; McCardle v. Indianapolis Water Co., supra; Los Angeles Gas & Electric Corp. v. Railroad Commission, supra. But even though it is an element for appropriate inclusion in the rate base, there is no constitutional exaction that it be separately stated as such and added to cost figures attributable the physical properties. Columbus Gas & Fuel Co. v. Public Utilities

Commission, 292 U. S. 398, 411; Denver Stock Yard Co. v. United States, 304 U. S. 470, 479; Driscoll v. Edison Light & Power Co., 307 U. S. 104; Federal Power Commission v. Natural Gas Pipeline Co., supra. The requirement may be satisfied if a reasonable allowance is "reflected in the other items and particularly in the appraisal of the physical assets as part of the assembled whole." Columbus Gas & Fuel Co. v. Public Utilities Commission, supra.

The amount claimed by the company was $175,000. A valuation engineer residing in New Jersey testified in support of the claim. He stated that he did not employ any mathematical formula in arriving at his conclusion as to amount, and he admitted that it was only a judgment figure. He stated with commendable candor that he reached it "just as a horsetrader looks at a horse and decides what it is worth". The record fails to indicate affirmatively whether the element was indirectly reflected to any extent in other items and in the appraisal of other properties as part of the assembled whole. But in any event, there is no basis on which to rest the conclusion that the failure of the Commission to state separately and add an amount as going concern value overstepped the limits of due process.

Allocation of Cost of Service—The orders are assailed for failure of the Commission to make a separation or allocation of the property used in regular business from that used in unregulated business. Under section 1 of the Act, natural gas moved in interstate commerce and sold for ultimate distribution to the public is subject to regulation by the Commission, but gas transported in interstate commerce and not sold for such distribution to the public as well as gas sold intrastate is not subject to regulation. Each of these companies is engaged in both kinds of business. The Commission expressed its awareness of the necessity of determining the reasonableness or unreasonableness of the rates and charges subject to its jurisdiction, observed that this required the distribution of the total costs of operations, including depreciation, taxes, and a fair return, among the various customers served, individually or by appropriate groups, and commented that to the extent that such costs allocated to sales under the jurisdiction of the Commission were less than revenues received, the rates

and charges made were unjust and unreasonable, and revenues must be reduced accordingly. The Commission further stated that it did not follow from that obligation that an allocation of physical property or portions thereof must be made before any excessive returns were determined. After observing that nowhere in all the evidence submitted by Canadian and Colorado was there a complete presentation of the entire operations, broken down between jurisdictional and nonjurisdictional operations, the Commission determined that all which could be accomplished by an allocation of physical properties could be attained by allocating costs including the return. And the Commission added that such method was by far the most practical and business-like. Following these observations, statements, and findings, the Commission made the allocation as to each company.

Where, as here, a natural gas company is engaged in an integrated business, part of which is subject to regulation and part of which lies beyond the reach of the regulatory jurisdiction of the Commission, some separation of the property, capital, and revenue is essential in order that regulation may be confined to its permitted field. The separation may be appropriately effected by estimating or appraising the value of the property used in the regulated business and that used in the unregulated business. Smith v. Illinois Bell Telephone Company, 282 U. S. 133. But that method in its completeness is not always exclusive of others. The separation or allocation may be effected by application of any formula which makes the principle a working one suitably adapted to the particular circumstances. Columbus Gas & Fuel Co. v. Public Utilities Commission, supra.

The integrated properties of these companies were designed and are being used in making both direct sales and resales. The companies rely on the same transmission and other facilities in serving both classes of customers, and both classes of customers jointly share the benefit of the same facilities and gas supply. In these particular circumstances, an allocation of the cost of supplying gas service to customers cannot be said to be a fatally inappropriate or infirm means of effectuating a separateness of the property and capital used in the integrated business.

But, assuming that the requisite separation may be accomplished by an allocation of cost of service, the method used by the Commission is said to be erroneous. It is argued among other things that it assumes that all of the property is used in common in the conduct of all business, whereas a large portion is used exclusively in the regulated portion, another part is used exclusively in the unregulated portion, and only a part is used in common in both businesses; that in respect to the property which is used in common for both businesses, it fails to give consideration to the priority or preferential use of such property in supplying gas for domestic consumption as against unregulated business, and ignores actual peak demands and load factors; that it operates to minimize all costs, produces apparent cost much less than actual cost, and shifts cost from regulated to unregulated business; and that it is unsound both in fact and law. It may be conceded, without deciding, that the method is not free from defects or imperfections in all its aspects. But even so it cannot be said that as the consequence, the impact of the orders of reduction, each in its totality, produces arbitrary results or oversteps the bounds of due process. Therefore the orders are not open to further judicial inquiry on these grounds. Federal Power Commission v. Natural Gas Pipeline Co., supra; Federal Power Commission v. Hope Natural Gas Co., supra.

Depletion, Depreciation and Amortization—The companies introduced evidence relating to accrued depreciation. It was based upon observed per cent condition of the property. Accrued depletion as determined by Canadian was based on estimates of original and remaining gas reserves. The evidence of the staff of the Commission treated accrued and annual allowances for depreciation on the basis of the application of the service-life principle. The Commission observed that if the theory of observed per cent condition of the property were carried out consistently, it might be considered as having some elements of reasonableness; that the small observed depreciation would find its counterpart in an equivalently small annual charge to operating expenses to cover the yearly added amount of observed depreciation; that this was not done in the estimates submitted by these

companies; that, instead, in calculating expenses chargeable to the consumer high depreciation charges were computed, and in computing return to the company a small deduction from the cost of plant was computed. And after full consideration, the Commission adopted the service-life principle for determining annual and accrued depreciation and the production method for determining annual and accrued depletion of production facilities.

Section 6 of the Act empowers the Commission to determine the depreciation in property used by a natural gas company, but it fails to prescribe the method to be used in the discharge of that function. Depreciation represents the loss, not restored by current maintenance, causing the ultimate retirement of the property. The factors entering into it usually are wear and tear, decay, inadequacy, and obsolescence. And in determining reasonable rates to be charged by a public utility, it is proper to include in the operating expenses an allowance for consumption of capital in order that the integrity of the investment in the service may be maintained. Lindheimer v. Illinois Bell Telephone Co., 292 U. S. 151.

As we understand, the Commission in arriving at accrued depreciation determined the amount to be deducted from original cost on the age-life basis by applying the straight life service method to the property. The contention that the testimony of valuation engineers who examined the property and made estimates in respect of its condition should have been accepted in preference to calculations based on averages and assumptions finds its genesis in Pacific Gas & Electric Co. v. City and County of San Francisco, 265 U. S. 403, and McCardle v. Indianapolis Water Co., supra. But there is no basis in this record on which it can be concluded that the determination of depreciation in the manner adopted by the Commission will result in any of these orders in its entirety causing a failure to restore the capital investment at the end of the term, and therefore no deprivation of property is involved. Once more, in the absence of impingment upon due process, review is ended. Federal Power Commision v. Natural Gas Pipeline Co., supra; Federal Power Commission v. Hope Natural Gas Co., supra.

Gas Reserves—In connection with its determination of annual allowances for depreciation and depletion, the Commission found that Canadian's remaining recoverable gas reserves as of December 31, 1939, were not less than 2,800,000,000 Mcf at 14.65 pounds pressure base and an abandonment pressure of approximately 50 pounds; and that at the then present and expected future rate of production of about 55,000,000 Mcf per year, such reserves would last 53 years. The finding is characterized as arbitrary, capricious, and without any basis in the record. It is said that the reserves were much less in amount and that as a source of supply for long distance pipe lines they will not extend in width beyond 1956. The field is about 125 miles long and varies from 10 to 40 miles. It comprises approximately 1,500,000 acres, of which about 1,000,000 acres produce sweet gas, and some 500,000 acres produce sour gas. Oil is produced in a portion of the field. Natural gas was discovered in 1918, on acreage now owned by Canadian; and at the time of the hearings in these proceedings there were about 1650 wells producing gas only, and about 4200 wells producing both oil and gas.

The two methods most frequently used in estimating recoverable gas reserves are the rock pressure decline method and the sand thickness porosity method. Using the pressure decline method, an experienced geologist and petroleum engineer on the staff of the Commission testified at length. He estimated that the reserves for the entire field were 22,420,000,000 Mcf, and that those of Canadian were 3,645,213,000 Mcf. For the purpose of determining the true average or equilibrium pressure prevailing throughout the field, he divided the field into areas of comparatively equal pressures, called quadrants, and made an estimate for each quadrant. His estimate in the aggregate was the sum of his estimates for the several quadrants. A scientific article published in 1933 was introduced in evidence in which the recoverable reserves in the field were estimated to be 16,100,000,000 Mcf. Two qualified experts testified for Canadian. One used the sand thickness porosity method, and he estimated that the reserves in the field amounted to 9,532,027,596. The other used the open flow method which is a variation of the sand thickness porosity method, and his estimate of the field was 8,[illegible]0,132,111 Mcf. And there

was much other evidence having bearing upon the question. The Commission found itself unable to accept in toto any of the estimates. The Commission observed that the pressure decline method is recognized as a satisfactory method of estimating gas reserves in fields that are depleted as much as fifteen per cent or more and where reliable pressure and production data are available; that the Texas Panhandle Field met these qualifications; that it was a well developed field; and that the pressure and production records maintained by the Railroad Commission of that state were adequate and satisfactory. The Commission found that the pressure decline method was to be desired over the methods used by the witnesses for the company; that the estimates of the witnesses for the company were not founded on proper data and must be considered essentially unreliable; that if the method of averaging quadrants was incorrect, it favored the company position of lower reserves; that the acreage of the company was among the very best in the entire field; and that after weighing all pertinent facts of record and making due allowance for the criticisms of the estimate submitted by the Commission staff, the recoverable reserves were found to be not less than 2,800,000,000 Mcf of gas.

The rock pressure decline method of estimating recoverable reserves of natural gas is not only accepted practice among mining engineers but it has been accorded judicial recognition. Dayton Power & Light Co. v. Public Utilities Commission, 292 U. S. 290. It lay within the discretion of the Commission to select that method as the most satisfactory and reliable means of determining the reserves of Canadian. And the Commission was not required to accept at face value the opinion evidence of the witnesses who testified as experts in respect to volume. The weight to be given to their evidence was a matter for the appraisal and judgment of the Commission, in the light of the circumstances. Existing volume, pressure differentials and consequent drainage, and other recovery factors should be given consideration in arriving at a final conclusion concerning the reserves. But it nowhere appears that the Commission failed appropriately to weigh these elements.

As has already been said, section 19(b) of the Act

provides that a finding of fact made by the Commission shall be conclusive on review if it is supported by substantial evidence. Congress thus committed to the Commission the function of weighing evidence, drawing inferences from the facts and circumstances established, and choosing between conflicting inferences. And a court is not free to substitute its view of the facts for that of the Commission. The underlying considerations which actuated Congress in vesting that power in the Commission are clear. The Commission often deals with subjects which are specialized, technical, and complex. It is relatively better staffed for its task than are the courts. And its members frequently bring to the discharge of their duties rich experience in those particular fields. The determination of the recoverable reserves of this company necessarily involved specialized and technical factors. The evidence relating to the question extends to great lengths. No useful end would be served by a detailed analysis of it. We think the finding is supported by substantial evidence and therefore is not vulnerable to the charge of lacking basis in the record.

Fair Rate of Return—The evidence submitted by the companies relating to a fair annual return upon the rate base varied in amount from 8 per cent to 9.17 per cent, while that of the Commission staff was 6½ per cent. The Commission fixed 6½ per cent for all three companies. The Commission stated in that connection that there was no exact formula for determining a reasonable rate of return: that in the final analysis the rate must be the best judgment of the Commission, founded upon the evidence and guided by the basic facts required by law to be considered: that consideration must be given to the return earned by like investments which are attended by corresponding risks and uncertainties in the same vicinity over the same period of time; that Canadian had a long-term and essentially cost of service contract with its affiliate, Colorado; that the sales of Colorado and Wyoming were also principally to subsidiaries or affiliates and to stable markets; that Colorado's principal industrial sales were also to an affiliate—Colorado Fuel and Iron Corporation; and that all these facts materially reduced basic business risks that might be present under other circumstances.

The rate of return which will constitute just compensation depends upon the circumstances. A public utility is entitled to such rates as will permit it to earn a return on the value of its property devoted to the convenience of the public substantially equal to that generally being earned in that area by other business enterprises which are attended by corresponding characteristics, including uncertainties, risks, hazards, and other elements affecting the operations. The return should be sufficient in amount to assure confidence in the financial soundness of the utility, and to enable it under efficient management to maintain its credit. Bluefield Water Works & Improvement Co. v. Public Service Commission, supra. But no formula can be laid down which will apply uniformly in all cases or to all kinds of utilities. That which is fair for one may be quite inadequate for another, depending upon the difference in circumstances. And the ascertainment of a fair return in a given case is a matter incapable of exact mathematical demonstration. It is one of reasonable approximation having its basis in a proper consideration of all relevant facts. Willcox v. Consolidated Gas Co., supra; United Railways and Electric Co. v. West, 280 U. S. 234.

Making application of these principals, and taking into consideration the history of these companies, their relations and opportunities, their position for future financing, the stability of demand for their product, and other relevant factors, we think that a return of 6½ per cent on the rate base as fixed by the Commission is not so inadequate as to amount to confiscation. Federal Power Commission v. Natural Gas Pipeline Co., supra; Federal Power Commission v. Hope Natural Gas Co., supra.

Finally, the Commission made allowances for working capital and additions to plant of all three companies, and these are attacked for insufficiency in amount; the Commission rejected some claims, and the companies predicate error on that action; and the Commission made certain adjustments, of which the companies complain. We do not discuss these seriatim. To do so would only extend this opinion, without adding anything of value to the accelerating accumulation of judicial utterances. The Commission was empowered to make pragmatic adjustments for which the

particular circumstances call. Federal Power Commission v. Natural Gas Pipeline Co., supra. On the whole record, we are unable to say that any of these orders in its total effect produces any arbitrary result or does violence to due mission v. Natural Gas Pipeline Co., supra; Federal Power Commission v. Hope Natural Gas Co., supra.

The orders are severally

AFFIRMED.

Decree, No. 2550.

Twenty-seventh Day, May Term, Saturday, July 8th, A. D. 1944. Before Honorable Orie L. Phillips, Honorable Sam G. Bratton and Honorable Alfred P. Murrah, Circuit Judges.

This cause came on to be heard on the transcript of record from the Federal Power Commission, and was argued by counsel.

On consideration whereof, it is now here ordered, adjudged and decreed by this Court that the orders of March 18, 1942 and April 22, 1942 of the Federal Power Commission in this cause be, and the same are hereby affirmed.

Decree, No. 2551.

Twenty-seventh Day, May Term, Saturday, July 8th, A. D. 1944. Before Honorable Orie L. Phillips, Honorable Sam G. Bratton and Honorable Alfred P. Murrah, Circuit Judges.

This cause came on to be heard on the transcript of record from the Federal Power Commission, and was argued by counsel.

Upon consideration whereof, it is now here ordered, adjudged and decreed by this Court that the orders of March 18, 1942 and April 22, 1942 of the Federal Power Commission in this cause be, and the same are hereby affirmed.

Stay Order.

Twenty-seventh Day, May Term, Saturday, July 8th, A. D. 1944. Before Honorable Orie L. Phillips, Honorable Sam G. Bratton and Honorable Alfred P. Murrah, Circuit Judges.

This matter coming on for hearing this day before the Court on the motion of petitioner for continuance of stay order and stay of issuance of mandate; and the Court having considered said motion, as well as motion of the City and County of Denver to dismiss said motion of petitioner, and the argument thereon;

And the Court having this day entered its judgment herein pursuant to the Court's opinion heretofore filed in this cause:

It is now ordered that the stay order entered herein on May 16, 1942, on the terms and conditions therein set forth, be and the same is hereby continued in full force and effect for the period of 60 days from and after the date hereof, and if within said period of 60 days a petition for certiorari is filed in the Supreme Court of the United States and a certificate thereof is filed in this Court within said 60 days pursuant to Rule 28 of this Court, then said stay order shall continue in full force and effect until final disposition of said cause by the Supreme Court of the United States.

It is further hereby ordered that issuance of mandate is hereby stayed for said period of 60 days from and after the date hereof, and if within said 60 day period petition for certiorari shall be filed in the Supreme Court of the United States, with due certification as aforesaid, then issuance of mandate shall be stayed until final disposition of said cause by the Supreme Court of the United States.

Clerk's Certificate.

United States Circuit Court of Appeals, Tenth Circuit.

I, Robert B. Cartwright, Clerk of the United States Circuit Court of Appeals for the Tenth Circuit, do hereby certify the foregoing, consisting of eight volumes, as a full, true, and complete copy of the designated transcript of the record from the Federal Power Commission, and full, true,

and complete copies of certain pleadings, record entries and proceedings, including the opinion (except full captions, titles and endorsements omitted in pursuance of the rules of the Supreme Court of the United States) had and filed in the United States Circuit Court of Appeals for the Tenth Circuit in certain causes in said United States Circuit Court of Appeals, No. 2550, wherein Colorado Interstate Gas Company, a corporation, was petitioner, and Federal Power Commission et al. were respondents, and No. 2551, wherein Canadian River Gas Company, a corporation, was petitioner, and Federal Power Commission et al. were respondents, as full, true, and complete as the originals of the same remain on file and of record in my office.

In Testimony Whereof, I hereunto subscribe my name and affix the seal of the United States Circuit Court of Appeals for the Tenth Circuit, at my office in Denver, Colorado, this 19th day of July, A. D. 1944.

(Seal, U. S. Circuit Court of Appeals, Tenth Circuit.)

ROBERT B. CARTWRIGHT,
Clerk of the United States Circuit Court of Appeals, Tenth Circuit.

SUPREME COURT OF THE UNITED STATES, OCTOBER TERM, 1944

No. 379

ORDER ALLOWING CERTIORARI—Filed November 13, 1944

The petition herein for a writ of certiorari to the United States Circuit Court of Appeals for the Tenth Circuit is granted, limited to the fifth and sixth questions presented by the petition for the writ. The case is assigned for argument immediately following No. 296.

And it is further ordered that the duly certified copy of the transcript of the proceedings below which accompanied the petition shall be treated as though filed in response to such writ.

SUPREME COURT OF THE UNITED STATES, OCTOBER TERM, 1944

Nos. 379 & 380

ORDER ALLOWING CERTIORARI, ETC.—January 2, 1945

A petition for rehearing and for enlargement of the scope of review having been filed in case No. 380 by counsel for the Canadian River Gas Company.

Upon consideration thereof, it is ordered by this Court that the said petition for rehearing in case No. 380 be, and the same is hereby, granted.

It is further ordered that the order entered November 13, 1944, be, and the same is hereby, vacated; and that the petition for writ of certiorari herein be, and the same is hereby, granted limited to question 1, 2, 3, and 8 presented by the petition for the writ and the case is assigned for argument immediately following No. 379. Case No. 379 is transferred to the summary docket.

It is further ordered that the duly certified copy of the transcript of the proceedings below which accompanied the petition shall be treated as though filed in response to such writ.

"* * * While the difficulty in making an exact apportionment of the property is apparent, and extreme nicety is not required, only reasonable measures being essential (Rowland v. Boyle, 244 U. S. 106, 108, 61 L. Ed. 1022, 1023, P.U.R. 1917E, 685, 37 S. Ct. 577; Groesbeck v. Duluth, S. S. & A. R. Co., 250 U. S. 607, 614, 63 L. Ed. 1167, 1172, P.U.R. 1920A, 177, 40 S. Ct. 38) it is quite another matter to ignore altogether the actual uses to which the property is put. It is obvious that, unless an apportionment is made, the intrastate service to which the exchange property is allocated will bear an *undue burden*—to what extent is a matter of controversy. We think that this subject requires further consideration, to the end that by some practical method the different uses of the property may be recognized and the return properly attributable to the intrastate service may be ascertained accordingly." (Emphasis supplied.)

Not only does the lack of a separation of property in the Commission's evidence and findings leave its conclusion as to rates a matter of guesswork and baseless, but we submit that we have in the respects above specified been able to demonstrate that its substitute, "cost allocation," has actually operated to shift the cost from the regulated to the unregulated business, and that its Order thereby operates to deprive the petitioner of earnings truly applicable to its unregulated business. The Order, in thus shifting the cost from the regulated to the unregulated business, not only violates statutory standards, but deprives the petitioner of its property, contrary to the due process clause of the Fifth Amendment to the Constitution.

The court below in its Opinion apparently recognized these defects in the Commission's "allocation of costs," but refused us any relief from the Commission's Order, because of its interpretation, erroneous we believe, of this Court's decisions in *Federal Power Commission v. Hope Natural Gas Co.*, supra, and *Federal Power Commission v. Natural Gas Pipeline Co.*, 315 U. S. 575. The Circuit Court (142 Fed. (2d) 943; at 959) said:

"* * * It may be conceded, without deciding, that the method is not free from defects or imperfections in all

its aspects. But even so it cannot be said that as the consequence, the impact of the orders of reduction, each in its totality, produces arbitrary results or oversteps the bounds of due process. Therefore the orders are not open to further judicial inquiry on these grounds. Federal Power Commission v. Natural Gas Pipeline Co., supra; Federal Power Commission v. Hope Natural Gas Co., supra."

Apparently the Circuit Court construes this Court's opinion in the two cases to mean that if "the total effect of the rate order cannot be said to be unjust and unreasonable," then methods and standards are no longer important and judicial inquiry is at an end. Our first observation is, that the "total effect" or "impact" of the rate order in this case is, on its face, unjust and unreasonable. An order which fixes the cost of gas delivered at La Junta to be 24.3 cents per Mcf, and the cost at Denver to be only 15.4 cents per Mcf (R. V. 1, p. 181), despite the fact that the Denver gas has to be compressed more often, and is transported approximately 145 miles farther; is not only unjust and unreasonable, but obviously arbitrary.

Our next observation is that we do not believe that this Court intended to construe the Act to mean that no separation of property is necessary in a case like the present one. In the *Hope* case, 320 U. S. 591, this Court said:

"* * * The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'."

It cannot be denied that property separations were recognized and standard procedures in rate making at the time of the adoption of the Act. Even though it be claimed for the Commission that it now possesses some mysterious instinct for reasonable rates, there is nothing in the Act to support any construction that the Commission can so fix rates without regard to such standards, and we do not interpret this Court's decisions as placing any such construction upon the Act.

But if the Act be construed as containing no such standards

and requirements, then it amounts to a naked delegation of the legislative power of Congress, contrary to the Constitution. Either it does contain such standards, in which case the Order is invalid because of their nonobservance, or it does not include such standards, in which case the whole Act and all orders based thereon are void because of such an unconstitutional delegation of legislative power.

No appraisal by this Court of the "end result" or "impact" of the Order, or of the rates fixed as being reasonable, can possibly excuse the admitted failure to make any separation of property, and the consequent violation of constitutional and statutory limitations. To put any such construction on the statute, and to approve any such order, would not only make Congressmen out of the members of the Power Commission, but would grant to them an immunity from constitutional limitation that even Congress itself does not possess.

THE RELATIONSHIP BETWEEN THE ORDER IN THIS CASE AND THAT INVOLVED IN CANADIAN'S CASE, No. 380.

In our petition for certiorari we called attention to the fact that Canadian River Gas Company was simultaneously filing a petition for certiorari, and that the two petitions were made on a joint Printed Record in the Circuit Court of Appeals, and that the two cases were companion cases. On page 9 of Colorado Interstate's petition we said:

> "A part of the reduction of $2,065,000 per year ordered by the Commission as against your petitioner is based upon a reduction ordered in the Canadian case in the price of gas sold by Canadian to petitioner in the amount of $551,000 per annum. In the companion case involving Canadian, it is contended that the Commission and the Court erred in ordering and approving this reduction in the cost of gas, and should Canadian be sustained in its contention that this reduction of $551,000 should not have been ordered, in whole or in part, then it would necessarily follow that the $2,065,000 reduction should be reduced accordingly, and this is a very special reason why, as already indicated, the two petitions for certiorari should be considered together."

This is all the more important now that this Court on petition for rehearing has enlarged the issues to be reviewed in Canadian's case to include three additional questions, because if for any one of the reasons assigned by Canadian in such enlarged review it should be held that the Commission's order reducing the price of gas charged by Canadian to Colorado Interstate is erroneous, then it would follow that the \$2,065,000 reduction ordered in Colorado Interstate's case should be reduced accordingly.

When an order is entered in this case it should require the Commission to take cognizance of any revision of the reduction ordered in the Canadian case, and should require the Commission correspondingly to reduce the ordered reduction made by it against Colorado Interstate.

CONCLUSION.

For the reasons set forth herein, the judgment of the Circuit Court of Appeals should be set aside and the case remanded with instructions to enjoin the Order of the Commission.

Respectfully submitted,

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January 8, 1945.

APPENDIX A.

The pertinent provisions of the Natural Gas Act of 1938 (52 Stat. 821, et seq.; Title 15, U.S.C.A., Sec. 717) are as follows:

Sec. 1 (b). "The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas."

Section 4 (a). "All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b). "No natual-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c). "Under such rules and regulations as the Commission may prescribe, every natural-gas company shall file with the Commission, within such time (not less than sixty days from the date this Act takes effect) and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection, schedules showing all rates and charges for any transportation or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services."

Section 5 (a). "Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: *Provided, however,* That the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company; but the Commission may order a decrease where existing rates are unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates."

Section 6 (a). "The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property."

Section 19 (b). "Any party to a proceeding under this Act aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the circuit court of appeals of the United States for any circuit wherein the natural-gas company to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be served upon any member of the Commission and thereupon the Commission shall certify and file with the

court a transcript of the record upon which the order complained of was entered. Upon the filing of such transcript such court shall have exclusive jurisdiction to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings, which if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in sections 239 and 240 of the Judicial Code, as amended (U.S.C., title 28, secs. 346 and 347)."

APPENDIX "B" EXHIBIT 138